NORTH CAROLINA
DIVISION OF AIR QUALITY
Preliminary Determination and Statement of Basis

Issue Date: xx

Region: Raleigh Regional Office
County: Person
NC Facility ID: 7300056
Inspector's Name: Matthew Mahler
Date of Last Inspection: 06/27/2018
Compliance Code: 5 / In Physical Compliance

Facility Data

Applicant (Facility's Name): CPI USA North Carolina - Roxboro Plant

Facility Address:
CPI USA North Carolina - Roxboro Plant
331 Allie Clay Road
Roxboro, NC 27573

SIC: 4911 / Electric Services
NAICS: 221112 / Fossil Fuel Electric Power Generation

Facility Classification: Before: Title V **After:** Title V
Fee Classification: Before: Title V **After:** Title V

Permit Applicability (this application only)

SIP: 02D .0530
NSPS: N/A
NESHAP: N/A
PSD: CO
PSD Avoidance: N/A
NC Toxics: N/A
112(r): N/A
Other: N/A

Contact Data

Facility Contact	Authorized Contact	Technical Contact
Virginia (Ginny) Grace Senior Advisor, Environment (910) 343-6711 1281 Powerhouse Drive, SE Southport, NC 28461	Terry Nealy Plant Manager (336) 330-4502 331 Allie Clay Rd. Roxboro, NC 27573	Virginia (Ginny) Grace Senior Advisor, Environment (910) 343-6711 1281 Powerhouse Drive, SE Southport, NC 28461

Application Data

Application Number: 7300056.17A
Date Received: 02/28/2017
Application Type: Modification
Application Schedule: PSD

Existing Permit Data

Existing Permit Number: 05856/T20
Existing Permit Issue Date: 09/09/2016
Existing Permit Expiration Date: 08/31/2021

Total Actual emissions in TONS/YEAR:

CY	SO2	NOX	VOC	CO	PM10	Total HAP	Largest HAP
2017	2410.10	466.34	12.01	733.16	62.99	34.46	7.31 [Fluorides (sum of all fluoride]
2016	2315.30	441.17	11.40	834.91	59.22	31.39	6.74 [Fluorides (sum of all fluoride]
2015	2005.70	408.77	9.61	727.79	53.83	26.50	5.63 [Fluorides (sum of all fluoride]
2014	1659.80	375.39	14.58	618.44	37.69	22.17	4.93 [Hydrogen fluoride (hydrofluori]
2013	1458.10	384.58	15.64	518.42	76.02	25.37	4.82 [Hydrogen chloride (hydrochlori]

Review Engineer: Rahul Thaker

Review Engineer's Signature: **Date:** July 15, 2019

Comments / Recommendations:
Issue: 05856/T21
Permit Issue Date: xx
Permit Expiration Date: xx

1.0 Purpose of Application

CPI USA North Carolina LLC, Roxboro, NC (CPI or CPI Roxboro), submitted a Prevention of Significant Deterioration (PSD) application (7300056.17A) for the previously-approved modification (Air Quality Permit No. 05856T10, March 31, 2009, Application No. 7300056.08A, Complete Application Receipt Date 11/19/08).

The applicant requested that this application be processed using the two-step procedure in accordance with 02Q .0504: That is, processing of the first (this submitted) application in accordance with 02Q .0300 and the second application per 02Q .0500 after its submittal within 12-months of commencement of operation of equipment.

North Carolina Division of Air Quality (DAQ) determined that because the affected equipment in the subject application have already been permitted and in operation, in addition to the fact that this significant modification would contravene or conflict with the existing permit condition, it would be appropriate to process the application using the 1-step procedure in 15A NCAC 02Q .0501(c)(1); thus, satisfying the permitting requirements in both 02D .0530 (PSD) and 02Q .0500 (Title V) in a single permitting action.

The application has been deemed "complete" for Prevention Significant Deterioration (PSD) with respect to the initial information submitted effective April 26, 2019.

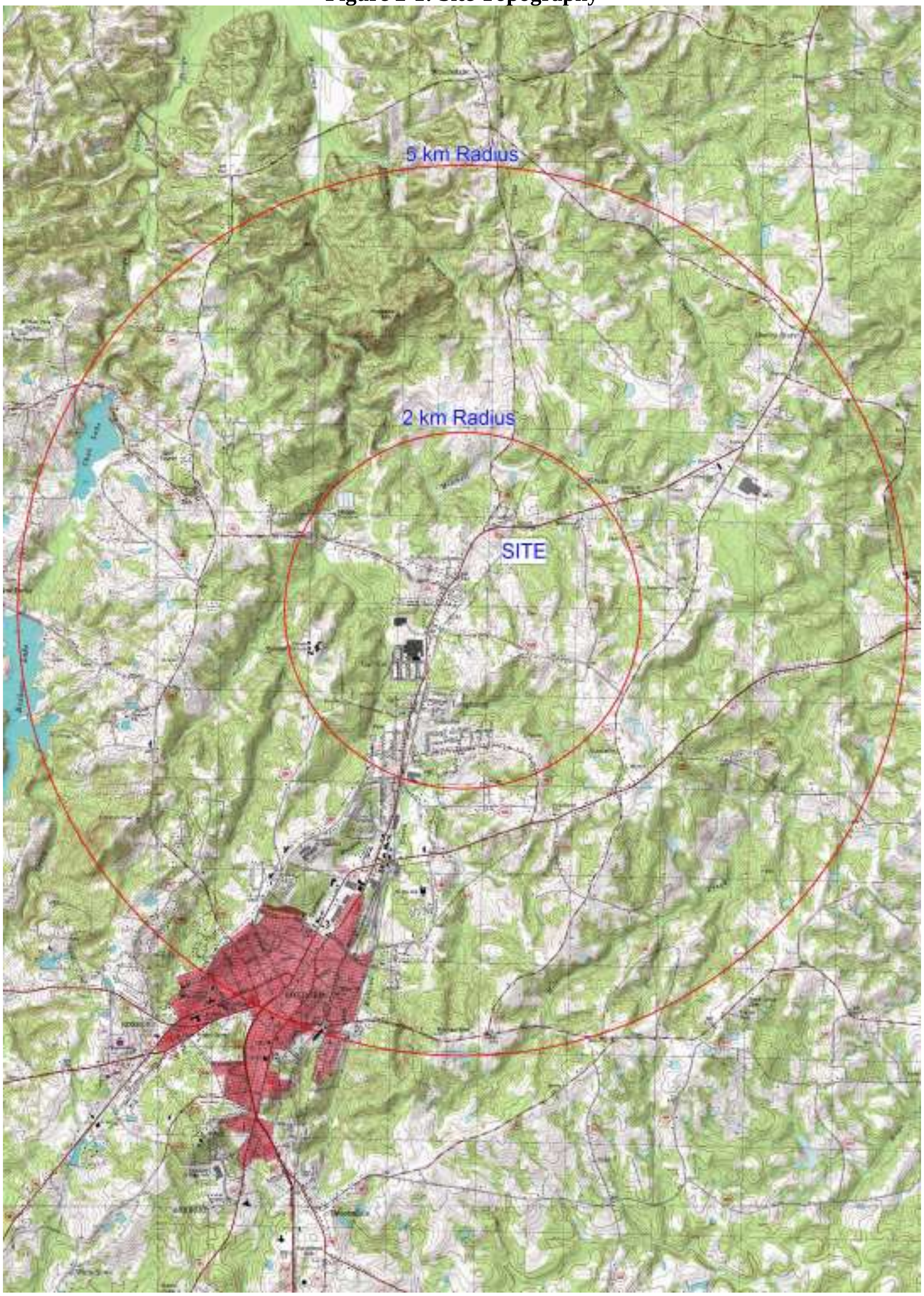
2.0 Facility Operations

2.1 Site Description

CPI Roxboro facility is located on 331 Allie Clay Road, Roxboro, Person County, NC, at latitude 36^0 26' 06" and longitude 78^0 57' 39", UTM Zone 17. The facility is located a few miles northwest of downtown Roxboro. The topography of the site and the surrounding area are exhibited in Figure 2-1 below:

The facility is located in a relatively rural area surrounded by forest and agricultural land. The topography is generally rolling hills, with terrain below stack top within 10 miles of the facility.

Figure 2-1: Site Topography



Current air quality designations for Person County with respect to promulgated National Ambient Air Quality Standards (NAAQSs) are described in Table 2-1 below in accordance with 40 CFR 81.334 "North Carolina":

Table 2-1: Attainment Status Designations

Pollutant	NAAQS	Designations
PM_{10}	150 ug/m^3 (24-hour)	Attainment (2012 (24-hour) NAAQS)[1]
$PM_{2.5}$	35 ug/m^3 (24-hour) 12 ug/m^3 (annual)	Unclassifiable/Attainment (Both 2006 (24-hr) and 2012 (annual) NAAQSs)
Sulfur Dioxide	0.03 ppm (annual) 75 ppb (1-hour)	Attainment (1971 (annual) NAAQS)[2] Attainment/Unclassifiable (2010 (1-hr) NAAQS)[3]
Nitrogen Dioxide	53 ppb (annual) 100 ppb (1-hour)	Attainment (1971 (annual) NAAQS)[4] Unclassifiable/Attainment (2010 (1-hr) NAAQS)
Carbon Monoxide	35 ppm (1-hour) 9 ppm (8-hour)	Unclassifiable/Attainment (1971 (Both 1-hr and 8-hr) NAAQSs)[5]
Ozone	75 ppb (8-hour) 70 ppb (8-hour)	Unclassifiable/Attainment (2008 (8-hr) NAAQS) Attainment/Unclassifiable (2015 (8-hr) NAAQS)
Lead	0.15 ug/m^3 (3-months)	Unclassifiable/Attainment (2008 (3-month) NAAQS)

In summary, Person County is either in attainment or attainment/unclassifiable of all promulgated NAAQS. Further, this County is considered a Class II area with ambient air increments for PM_{10}, $PM_{2.5}$, SO_2, and NO_2. The closest Class I area from this facility is Swanquarter National Wilderness Area, which is located approximately 158 miles (254 kilometers) southeast of the facility.

2.2 Existing Operations

CPI owns and operates an electric power producing facility in Roxboro, Person County, North Carolina. The plant began operation in 1987 and was initially permitted (1986-1987 circa) as a major stationary source under the Prevention of Significant Deterioration (PSD) regulation. It was originally designed as a cogeneration facility, producing steam for Collins & Aikman facility, and selling electricity to former Progress Energy (now Duke Energy Progress (DEP)). However, the Collins & Aikman plant shut down in 2006 and since that time, CPI has been producing electricity only and selling it to DEP. The facility's primary business activity is classified under the Standard Industrial Classification (SIC) code 4911 "Electric Services."

The facility comprises of three stoker boilers (each 220 million Btu per hour nominal heat input rate), designed to burn solid fuels, and ancillary equipment. The facility's maximum power output capacity is approximately 55 net megawatts (MW). The boilers are permitted to burn coal, tire-derived fuel (TDF), unadulterated wood (including bark, dry and wet wood), adulterated engineered wood, creosote treated wood, natural gas, Nos. 2 and 4 fuel oils, pelletized paper, and fly ash briquettes.

It should be noted that there is no infrastructure currently available to accomplish fuel burning for fuel oils or natural gas. For example, fuel feed systems and storage are not installed for either of these fuels. Moreover, a natural gas line does not currently extend to the plant site and it is questionable whether the nearest gas line (Route 501) can accommodate the capacity requirements, even if the gas burners had been installed on the boilers. In fact, the facility has never burned natural gas or fuel oil due to the above constraints, as per the Permittee. Further, for

[1] Assumed. Person County has been designated unclassifiable / attainment for more stringent PM2.5 NAAQSs for both 24-hr and annual averaging periods.

[2]The annual SO_2 NAAQS is effective in only certain areas of the country as per https://www.epa.gov/criteria-air-pollutants/naaqs-table.

[3] Only Cunningham Township of Person county remains to be designated, which will occur by 12/31/2020, as per EPA.

[4] The same 1971 NO_2 NAAQSs (primary and secondary) for annual averaging period were retained in 1985, 1996, 2010 and 2012.

[5] The same 1971 CO NAAQSs (primary) for both 1-hr and 8-hr averaging periods were retained in 1985, 1994 and 2011.

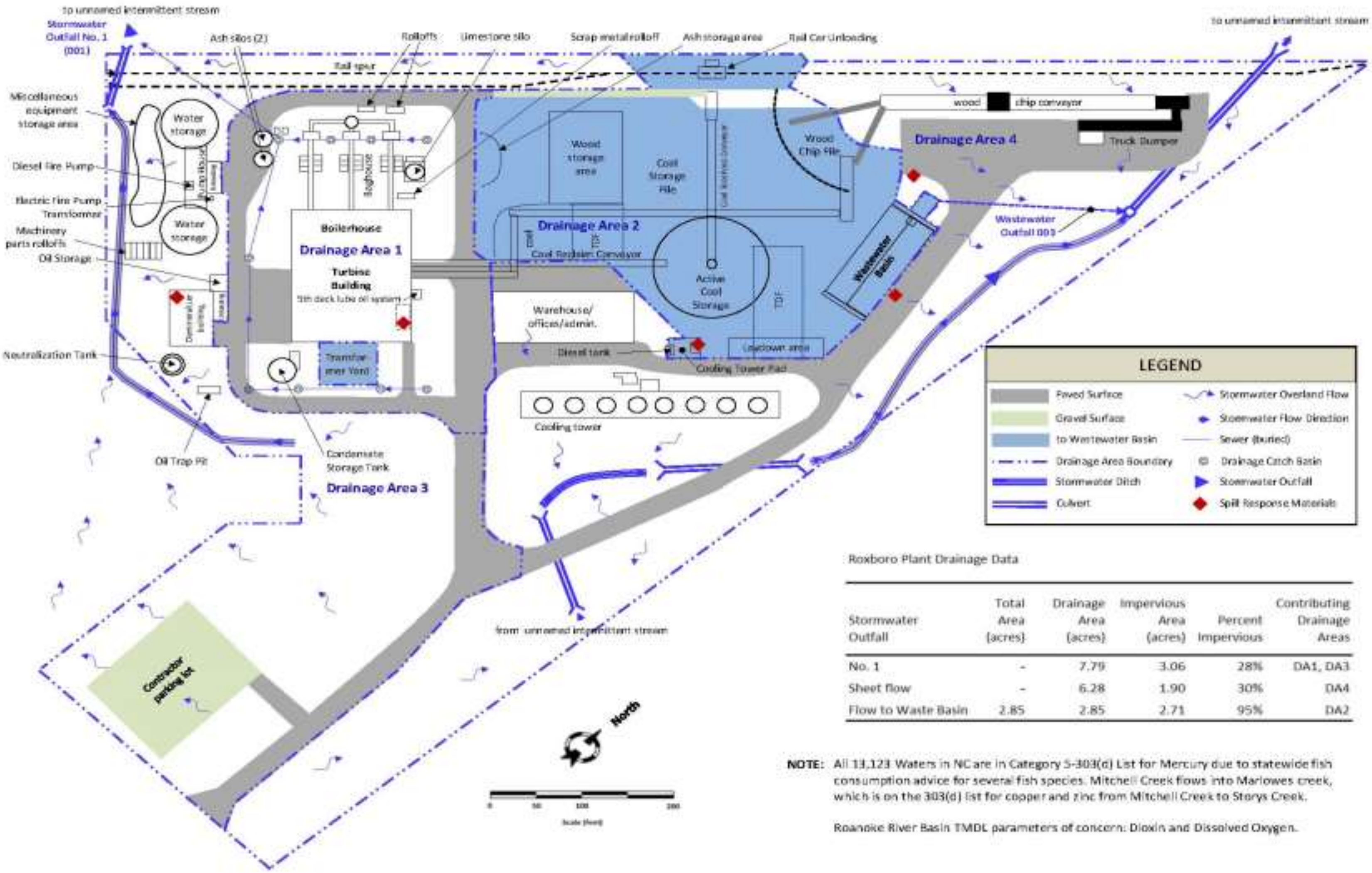
pelletized paper and fly ash briquettes, additional modifications to the existing material handling and fuel storage areas would be required for the facility to consistently burn any of these alternative fuels as viable long-term fuel options.

Thus, boilers currently burn and have the capability to burn coal, TDF, and wood fuels only. Currently they burn a blend of coal/TDF/wood in normal operations, at a ratio of 12 percent / 41 percent / 47 percent on a heat input basis, respectively. The facility uses a small amount of fuel oil (No. 2 fuel)-soaked paper during boiler startup (the quantity of oil during each startup is probably less than 1 gallon and fuel oil is not burned as a free liquid).

Regarding the use of TDF and wood burning in the boilers, it needs to be stated that the Roxboro facility is currently categorized as a Qualifying Facility (QF) under the Public Utility Regulatory Policies Act (PURPA) regulations. As per the Permittee, to maintain this QF status, the facility is required to have 75% of the fuel heat inputs from fuels other than coal, natural gas or fuel oil.

The boilers are equipped with a dedicated rotating over-fire air (ROFA) systems for NOx control. The existing permit also includes a selective non-catalytic reduction system (SNCR) as an optional control for NOx emissions for each boiler; however, the SNCR systems have not been installed and the Permittee has requested to remove them from the existing permit. For SO_2 and acid gases (such as sulfuric acid mist), each boiler is equipped with a dedicated furnace sorbent injection system (FSI). Finally, particulate matter (PM) emissions from the boilers are controlled by bagfilters.

Figure 2-2 below exhibits site layout, exhibiting various permitted sources:



Roxboro Plant Drainage Data

Stormwater Outfall	Total Area (acres)	Drainage Area (acres)	Impervious Area (acres)	Percent Impervious	Contributing Drainage Areas
No. 1	-	7.79	3.06	28%	DA1, DA3
Sheet flow	-	6.28	1.90	30%	DA4
Flow to Waste Basin	2.85	2.85	2.71	95%	DA2

NOTE: All 13,123 Waters in NC are in Category 5-303(d) List for Mercury due to statewide fish consumption advice for several fish species. Mitchell Creek flows into Marlowes creek, which is on the 303(d) list for copper and zinc from Mitchell Creek to Storys Creek.

Roanoke River Basin TMDL parameters of concern: Dioxin and Dissolved Oxygen.

Figure 2-2: Site Layout

3.0 Proposed Modification

3.1 Background

In 2008, the previous operator (EPCOR USA North Carolina, LLC) of the facility submitted an air permit application (7300056.08A), proposing to retrofit the plant's three (3) existing boilers with SO_2 and NO_x emissions controls and modify the boilers and fuel handling equipment to allow for additional biomass and TDF combustion. The requested changes were as follows:

- To increase the feed rate of TDF up to 50 percent from the permit-limit of 40 percent on a heat input basis for each boiler.
- To install an FSI on each boiler for SO_2 emissions control.
- To install one alkaline (limestone, lime or Trona) sorbent silo and associated bin vent fabric filter.
- To install a ROFA on each boiler for reducing NOx emissions.
- To install SNCR technology on each boiler for reducing NOx emissions.

The DAQ issued a minor New Source Review air quality permit 05856T10 on March 31, 2009 for the above modifications, which are referred to as the "2009 project" throughout this document.

As per the Permittee, the following changes were completed at the facility after receiving the permit:

(a) Installation of additional wood handling equipment to allow the facility to combust increased amounts of biomass,

(b) Installation of the NALCO ROFA and FSI systems on each boiler,

(c) Installation of an alkaline storage silo and an associated bagfilter.

As noted above, the Permittee did not install the SNCR systems for further controlling NOx emissions from the boilers and it does not plan to install them in future.

The above referenced air quality permit required record keeping and reporting of post-project actual emissions (PM, PM_{10}, NOx, SO_2, CO and VOC) for five calendar years from the resumption of normal operation for existing boilers. Due to an oversight on the part of DAQ in drafting the permit stipulation, the tracking and reporting of the actual emissions of these pollutants did not begin until the start of calendar year 2015. The post-project actual emissions for 2015 for CO (728 tons per year) exhibited emissions increase exceeding the significance threshold (100 tons per year) over the baseline emissions. The DAQ determined in 2016 that the 2009 project was a major modification for CO; thus, the Permittee was required to obtain a PSD permit before making the changes described above.

Therefore, as required, the Permittee submitted a PSD application post-hoc for this previously-approved 2009 project for emissions of CO in February 2017. During the review of the application, the DAQ questioned the methodology used to exclude certain emissions (demand growth) which could have been accommodated during the baseline period. CPI provided a response to the DAQ questions with a revised application in August 2017, without accounting for any excludable emissions. The DAQ concluded that the major modification provision under PSD was triggered for both CO and SO_2 for the 2009 project without the inclusion of questionable "demand growth". Finally, in order to remain consistent with the CPI's PSD application for its Southport NC facility, the Permittee again revised the PSD application for the Roxboro facility in September 2018, by completely replacing all previous submittals (February 2017 and August 2017), addressing emissions which could have been accommodated during the baseline period and concluding that the 2009 project triggered PSD for CO only (and not for SO_2).

3.2 Project Sources / Description

<u>Increase Combustion of Wood/Biomass and TDF</u>

Prior to the 2008 air permit application, the facility mostly combusted coal and TDF to produce steam and electricity. During the last 24 months of the look-back period, the facility combusted approximately 76.3 percent coal, 18.4 percent TDF, and 5.3 percent wood, on a heat input basis. After CPI modified the boilers and installed new fuel handling equipment, the facility burned approximately 12 percent coal, 41 percent TDF, and 47 percent biomass, on a heat input basis. CPI Roxboro now has the capability to combust even greater amounts of biomass in the fuel mixture.

Because wood/biomass has a much lower sulfur content and much higher moisture content relative to coal, the increased firing of wood/biomass has reduced the hourly rate of SO_2 and NO_x emissions on a per megawatt output basis.

Prior to the 2008 application, the Roxboro Plant was permitted to have a wood storage pad area, a portable hopper/conveyor, and a wood grinder. The facility has since added additional fuel handling equipment to significantly increase the combustion of wood/biomass over previous levels. Additional storage areas, conveyors, and grinding capacity were also installed to handle the increase in wood/biomass as follows:

- one truck scale;
- one wood fuel truck unloading/dump platform;
- one wood fuel dump hopper with chain conveyors;
- one horizontal wood fuel conveyor from hopper to main conveyor;
- one inclined wood fuel conveyor with metal detector and belt magnet;
- one 104 ton per hour disc screen;
- one 75 ton per hour wood hog/shredder;
- one inclined wood fuel conveyor to stacker;
- one portable radial stacker for wood fuel;
- new wood stockpile;
- one drag chain wood fuel reclaimers under wood stockpile;
- two, inclined/horizontal wood fuel conveyors in series to boiler building;
- one wood fuel belt weigh scale at boiler building;
- one wood fuel bin at boilers;
- one wood fuel drag chain conveyor from wood bins to screw feeders;
- three wood fuel screw feeders.

All of the equipment above was listed in the 2008 permit application and has been installed. Most of these sources any above have no emissions or negligible emissions.

The 2008 application indicated that the facility would install the following equipment to handle TDF delivery by rail in the future:

- Diverter chute to the existing coal stock out conveyor;
- Weigh scale for existing TDF reclaim conveyor;
- TDF conveyor to a new TDF stockpile located in the existing coal stockpile area;
- TDF reclaim/draw down hopper with vibrating feeder;
- TDF conveyor from the draw down hopper to the main coal conveyor.

From the above list, only the weigh scale for an existing TDF reclaim conveyor was installed. This scale is wholly unrelated to emissions or delivery by rail. The remainder of the equipment was not installed at the facility and the facility does not have (and has never had) the ability to handle TDF delivery by rail.

The modification to fire more wood did allow the plant to combust increased amounts of TDF in the fuel blend. The existing equipment at the plant, prior to the 2008 application, had the physical capability to deliver TDF up to 40 percent on a heat input basis. Firing increased amounts of TDF serves two purposes:

1. The higher flame temperatures associated with TDF helps offset the cooling influence of moisture in wood, helping to maintain proper combustion in the boiler and enabling the plant to burn a higher percentage of wood/biomass.

2. A percentage of TDF combusted contributed to renewable credits for the facility.

TDF has higher sulfur content, ranging from approximately 1 to 2 percent by weight on average, compared to coal (less than 1 percent). However, increasing the amount of biomass in the fuel mixture, which has very low sulfur content, helps to reduce the rate of uncontrolled SO_2 emissions.

ROFA (NO_x Control Technology)

CPI installed Mobotec's ROFA technology as its primary means to reduce NO_x. An Over-fire Air (OFA) system has the advantage of not only reducing NO_x emissions, but, also improves combustion efficiency by reducing CO and unburned carbon levels. Mobotec's ROFA system further improves mixing in a stoker grate boiler by dramatically increasing the velocity of the OFA air and by introducing a rotating flow within the furnace.

ROFA, is a state-of-the-art furnace staging and NO_x reduction system. The bulk flow air upward through the furnace is set in rotation with custom designed asymmetrically placed air nozzles. The overall effect is increased turbulent mixing and bulk rotation in the entire furnace. This improves gas temperature distribution, species distribution, heat absorption, CO oxidation, and particle burnout in the upper furnace.

Mixing and rotation prevents bulk laminar flow and enables the whole volume of the furnace to be used more effectively for the combustion process, as well as the sorbent mixing process. The ROFA swirl reduces maximum reaction temperature, reduces NO_x formation, burns out carbon more efficiently, and increases convective heat absorption, which in combination may improve the overall boiler efficiency.

By mixing the combustion air more effectively, ROFA also reduces the need for surplus excess air. This results in less cooling of the furnace due to unused combustion air, further increasing heat absorption efficiency. ROFA will significantly improve the effectiveness of the alkaline sorbent for the reduction of hydrogen chlorides, mercury, and SO_2.

The ROFA boxes are strategically placed along the furnace walls to optimize NO_x reduction and combustion intensity. Ultimately, the performance and functionality of the ROFA System works in conjunction with and is dependent on the overall furnace geometry and operation. The ROFA air is thereby injected in a manner that creates a rotational flow in the upper region of the combustion zone. The ROFA system results in the following combustion improvements:

- Reduced oxygen availability in the primary combustion zone, reducing the opportunity for NO_x formation;
- Turbulent mixing in middle and upper furnace region allowing completion of the combustion process in this secondary zone, reducing loss on ignition (LOI) and CO levels;
- More uniform temperature profile and heat distribution in the middle and upper furnace, reducing thermal stress and improving boiler efficiency;
- Evening of fuel-air distribution reducing pockets of low oxygen and high CO/combustibles, allowing the unit to be operated at lower levels of excess oxygen for improved efficiency;
- A turbulent, well-mixed region in which to inject agents such as SO_2 and Hg reduction sorbent and/or NO_x reduction chemical."

The following new equipment and modifications to existing equipment were completed for the ROFA system:

- Existing side OFA ports were removed and holes covered by refractory;
- New openings in the boiler water wall, one tube bend for each ROFA opening;
- Concrete foundations for three ROFA fans;
- Ductwork connecting the discharge of the forced draft fans to the inlet of the ROFA fans.

FSI (SO_2 Control Technology)

CPI installed FSI with the ROFA system. FSI involves the injection of a sorbent (e.g. limestone) in the boiler furnace area which reacts with acid gases to produce solid alkaline salts and reduce acid gas concentrations in the exiting flue gas.

Mobotec installed six ROFA ports on each boiler. Limestone is pneumatically conveyed to a select number of these ports to ensure sufficient distribution of the sorbent into the furnace at the optimum temperature region. The sorbent is carried into the boiler by the ROFA air.

After the sorbent is injected into the flue gas, it reacts with SO_2, SO_3, hydrochloric acid and other acid gases to form calcium (e.g., $CaSO_4$) and alkali salts. These calcium and alkali salts are particulates and are captured by the pulse-jet baghouses. An increase in emissions of filterable particulate is not expected from operation of FSI since the units are already equipped with highly efficient baghouses. The emissions of condensable particulate would decrease due to the removal of acid gases in the flue gas. As with any SO_2 treatment technology, the amount of SO_2 reduction will be dependent on the fuel sulfur content and loading rate, reagent type and loading rate, and mixing efficiency of reagent to flue gas.

The following new equipment and modifications to existing equipment were completed for the FSI system:

- Flexible hose connections for pneumatic air delivery to from trucks to the transfer piping;
- Three sorbent blowers;
- One alkaline sorbent silo with baghouse and associated concrete foundation;
- Sorbent preparation equipment;
- Sorbent injectors.

3.3 Project Schedule

As noted above in Sections 3.1 and 3.2, the project equipment has been installed and in operation, in addition to operational changes to the facility boilers. This application is merely a requirement to obtain a PSD permit in accordance with 02D .0530 for the previously permitted equipment and changes (2009 project).

3.4 Project Emissions

Emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, lead, sulfuric acid mist, GHG, and some NC-regulated air toxics are expected due to the burning of coal, TDF, and biomass in the modified boilers. The change in emissions, discussed in detail in Section 4.0, are summarized below, and reviewed for various regulatory applicability in Section 4.0 below:

- Particulate Matter (PM filterable only): -2.0 tons/year (TPY) [decrease]
- PM_{10}: -6.0 TPY [decrease]
- $PM_{2.5}$: -4.0 TPY [decrease]
- SO_2: -468.0 TPY [decrease]
- NOx: -129.0 TPY [decrease]
- CO: 539.0 TPY [increase]
- VOC: 3.0 TPY [increase]
- Lead: 0.0 TPY [decrease]
- Sulfuric Acid Mist: -5.0 TPY [decrease]
- Fluorides: -1.9 TPY [decrease]
- GHG (as CO_2e): -62,169.0 TPY [decrease]

The stack parameters for a peak (100 percent) load scenario include exhaust flow rate of 262,959 actual ft^3/min at an exit temperature of 350^0F.

4.0 Regulatory Applicability

The modified boilers and the alkaline sorbent storage silo are subject to the following requirements:

15A NCAC 02D .0501(c) Compliance with National Ambient Air Quality Standards

This rule requires facilities to comply with the ambient air quality standards (State ambient air quality standards (SAAQS), National air quality ambient standards (NAAQS)), listed in 02D .0400. If more stringent controls than the applicable standards in 02D .0500 are required to prevent a violation of ambient air quality standards, the permit shall include a condition requiring such controls.

For this applicable requirement, the DAQ had established the following emission limits for each of the existing boilers (ID Nos. ES-1-1A, ES-1-1B, and ES-1-1C):

a. PM_{10} emissions shall not exceed 5.94 pounds per hour per boiler.

b. SO_2 emissions shall not exceed 332.2 pounds per hour per boiler.

c. NOx emissions shall not exceed 121.0 pounds per hour per boiler.

d. CO emissions shall not exceed 121.0 pounds per hour per boiler.

The above limits are the same as the existing Best Available Control Technology (BACT) limits in lb/million Btu unit for these pollutants, corresponding to the maximum heat input rate for each boiler (220 million Btu/hr): 0.027 lb/million Btu (PM_{10}), 1.51 lb/million Btu (SO_2), 0.55 lb/million Btu (NOx), and 0.55 lb/million Btu (CO).

As stated in Section 2.1 above, Person County is either in attainment, attainment/unclassifiable, or unclassifiable/attainment, for all promulgated NAAQSs including 1-hr SO_2 and 1-hr NO_2 NAAQSs. In addition, the project results in reductions in emissions of -6 tons/yr (PM_{10}), -468 tons/yr (SO_2), and -129 tons/yr (NOx). Therefore, the DAQ believes that continued compliance with the promulgated NAAQSs for the above pollutants is expected.

With respect to the CO emissions increase from the project, the predicted worst-case impacts (539 ug/m^3 (1-hr) and 485 ug/m^3 (8-hr) are less than the Class II area (such as Person County airshed) significant impact levels (SILs) of 2000 ug/m^3 and 500 ug/m^3, respectively. Therefore, it is concluded that the facility is expected to continue complying with the CO NAAQS (both 1-hour and 8-hour).

With respect to monitoring for PM10 emissions, the existing permit contains inspection and maintenance requirements for the baghouses associated with each of the boilers such as annual internal inspection of these control devices. The permit also requires weekly monitoring of pressure drop across each of the bagfilters with a target of not to exceed 10 inches of water.

For SO_2, the Permittee is required to monitor emissions using a Part 75-compliant continuous emission monitoring system (CEMS) on a 24-hour block average basis.

For NOx, the Permittee is required to monitor emissions using a Part 75-compliant CEMS on a 30-day rolling average basis.

For CO, the Permittee is required to monitor emissions using a CEMS on a 30-day rolling average basis.

The Permit requires a semi-annual summary reports for data collected for each of these pollutants and a monitor availability report for both NOx and SO_2 CEMS.

No change to existing monitoring requirements including record keeping and reporting, as discussed above, is justified.

15A NCAC 02D .0516 Sulfur Dioxide Emissions from Combustion Sources

The existing boilers are subject to 2.3 lb/million Btu limit as per the current permit. The permit requires monitoring of emissions using a CEMS. Compliance is to be determined as a 24-hour block average for data collected using a Part 75-compliant CEMS. The permit also requires quarterly reporting of CEMS-collected 24-hour block average data, in addition to, CEMS monitor availability data.

No change to the existing monitoring requirements, including record keeping and reporting, as discussed above, is justified.

15A NCAC 02D .0524 New Source Performance Standards (NSPS)

The current permit includes all applicable requirements in NSPS Subpart Db for each of the boilers (ID Nos. ES-1A, ES-1B, and ES-1C).

The following emissions standards apply for emissions of PM (filterable only) and NOx from these boilers:

a. Particulate emissions from each boiler shall not exceed 0.05 pounds per million Btu heat input when firing coal with other fuels.

b. Each boiler shall not cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (six-minute average), except for one six-minute period per hour of not more that 27 percent opacity.

c. Nitrogen oxides from each boiler when firing coal shall not exceed 0.60 pounds per million Btu heat input.

d. Nitrogen oxides emissions from each boiler due to the simultaneous combustion of coal with fuel oil or a mixture of these fuels with natural gas or any other fuel shall not be in excess of the rate calculated by the following formula:

$$E_n = (0.1H_{go} + 0.3H_{ro} + 0.6H_c)/(H_{go} + H_{ro} + H_c)$$

Where: E_n = nitrogen oxide emission limit (lb/million Btu)
H_{go} = heat input from combustion of natural gas or distillate oil (million Btu)
H_{ro} = heat input from the combustion of residual oil (million Btu)
H_c = heat input from the combustion of coal (million Btu)

The current permit includes continuous emission monitoring requirements for visible emissions (opacity) and NOx. The permit also includes recordkeeping of amounts of each fuel burned each day, quarterly recordkeeping of nitrogen content of residual oil (if burned), record keeping of opacity, and daily record keeping of NOx emission rates. Finally, the permit includes reporting for excess emissions (NOx and opacity) and a semi-annual reporting for summary of all monitoring and record keeping activities for each of the calendar six-month periods.

§60.14 Modification

Pursuant to paragraph (a) and (b) of this Section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of Section 111 of the Clean Air Act (CAA). Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere. In addition, upon modification, any (currently) affected facility will need to comply with the presumably more stringent emission standards for the “modified” units, if there are any.

Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

Per subparagraph (b)(2) of the Section, the Permittee can use material balances, continuous monitor data, or manual emission tests to determine a change in emissions. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in Appendix C of 40 CFR shall be used to determine whether an increase in emission rate has occurred.

NSPS Subpart Db includes emissions standards for PM (filterable only), SO_2, and NOx, and associated monitoring, recordkeeping, reporting, notification, and performance testing requirements. This NSPS also includes emissions standards for a "modified" or "reconstructed" unit for PM (filterable only) and SO_2 only, if the unit is deemed modified or reconstructed after February 28, 2005.

As discussed above, the existing boilers at CPI Roxboro are subject to NSPS Subpart Db standards for PM and NOx. For the previously approved changes (2009 project), whether the modification provision has triggered for any affected boilers, the Permittee has submitted a change in emissions analysis following the required procedure in Appendix C to Part 60 "Determination of Emission Rate Change".

The Tables 4-1 through 4-7 below include pre- and post-modification emission rates for PM (filterable only), SO_2, and NO_2, and the analysis of whether an increase in emission rate has occurred:

Table 4-1: Pre-Modification Stack Test Data for SO_2 and Filterable PM

		SO_2	SO_2	Filterable PM	Filterable PM
Test Date	Run	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr
November-04	1	1.369	825.9	0.0046	2.80
	2	1.232	751.9	0.0052	3.20
	3	1.263	765.9	0.0070	4.22
November-05	1	1.227	816.97	0.0015	0.98
	2	1.211	791.58	0.0004	0.29
	3	1.193	787.13	0.0006	0.43
11/1/2006[6]	1	1.28	783.7	0.0023	1.45
	Arithmetic Mean =	1.253	789.01	0.00308	1.91
	Variance =	0.00346	682.03	6.43476E-06	2.28

Table 4-2: Pre-Modification CEMS Data for NOx

Date	Hour	lb/MMBtu	lbs/hr
11/16/2004	4	0.485	325.8
11/16/2004	5	0.402	305
11/16/2004	6	0.436	318.3
11/16/2004	7	0.435	332.2
11/16/2004	8	0.426	323.9
11/16/2004	9	0.427	322
11/16/2004	10	0.406	306.7
11/16/2004	11	0.392	297.7
11/16/2004	12	0.393	298.3
11/16/2004	13	0.372	282
11/16/2004	14	0.369	275.3
11/16/2004	15	0.3797	284.8
11/16/2004	16	0.371	280.7
11/16/2005	5	0.377	247.6
11/16/2005	6	0.362	255

[6] The AQAB Memorandum for this stack test event modified the results from the stack test report, submitted by TRC Corporation. The final average value from this AQAB Memo was used instead of each test run values (3-runs) presented in the report.

11/16/2005	7	0.379	266.4
11/16/2005	8	0.357	252.9
11/16/2005	9	0.353	255.5
11/16/2005	10	0.357	253.1
11/16/2005	11	0.348	248.9
11/16/2005	12	0.349	248.2
11/16/2005	13	0.345	245
11/16/2005	14	0.343	241.7
11/16/2005	15	0.361	257.1
11/16/2005	16	0.375	267.1
11/16/2006	11	0.309	213
11/16/2006	12	0.317	216.6
11/16/2006	13	0.318	216.8
11/16/2006	14	0.31	213.5
11/16/2006	15	0.301	205
11/16/2006	16	0.309	207.3
11/16/2006	17	0.331	213.9
11/16/2006	18	0.318	210.6
11/16/2006	19	0.321	215.1
Arithmetic Mean =		0.37	261.85
Variance =		0.00	1555.50

Table 4-3: Post-Modification Stack Test Data for Filterable PM

Test Date	Run	lb/million Btu	lb/hr
August-15	1	0.005	3.18
	2	0.005	3.55
	3	0.0030	2.25
	Arithmetic Mean =	0.00433	2.99
	Variance =	0.00000133	0.4486

Table 4-4: Analysis for SO_2

Test	Number of Data Points	Arithmetic Mean (lbs/hr)	Variance	Pooled Variance	t-test	t'
Pre-Modification: November 2004, 2005, and 2006 Stack Tests Data	7	789.011	682.032	97.82	-4.329	1.65
Post-Modification: 2015 CEMS Data at High Load	5,766	628.848	5482.409			

Table 4-5: Analysis for Filterable PM

Test	Number of Data Points	Arithmetic Mean (lbs/hr)	Variance	Pooled Variance	t-test	t'
Pre-Modification: November 2004, 2005, and 2006 Stack Tests Data	7	1.91	2.28	3.714264	0.422	1.81
Post-Modification: August 2015 Stack Test	3	2.993333333	0.4486			

Table 4-6: Analysis for NOx

Test	Number of Data Points	Arithmetic Mean (lbs/hr)	Variance	Pooled Variance	t-test	t'
Pre-Modification: CEMS Data Collected During November 2004, 2005, and 2006 Stack Tests	34	261.85	1555.50	226.6694	-3.537	1.65
Post-Modification: 2018 CEMS Data at High Load	6,651	123.98	47.636			

As per EPA, if after modification rate is greater than pre-modification emission rate and statistic t is greater than student t′, where t′ is the critical value of t obtained from Table 1 (of Appendix C), then, there is a 95% confidence that the difference between the pre- and post-modification emission levels is significant and an increase in emission rate to the atmosphere has occurred.

It needs to be noted that the evaluation of emission change for pre- and post-modification periods, pursuant to §60.14(b) and Appendix C to the Subpart 60, shall be performed on equal sample sizes, keeping the operational parameters constant to the extent possible, whether stack test data or CEMS data are used. Thus, as shown above, it would be inappropriate for PM to compare the average emission rate from all stack tests events of November 2004, 2005, and 2006 (combined total 9 runs) in a pre-modification period with the average emission rate derived from 2015 stack test event (total 3 runs) in a post-modification period and evaluate a change in emissions using the Student t-test methodology. Similarly, it would be inappropriate to perform the modification analysis for SO_2 using unequal sample size (combined total 9 runs in a pre-modification period and 5,766 data points for a post-modification period).

Thus, for PM, evaluating 2004 and 2015 events' average emission rates (3 runs each), as included in above tables, for pre- and post-modification scenarios, respectively, DAQ believes that NSPS modification provision <u>did not</u> trigger. Similarly, when comparing 2005 and 2015 events' average PM emission rates (3 runs each), the NSPS modification <u>did</u> trigger. Finally, when comparing 2006 and 2015 events' average emission rates (3 runs each), the NSPS modification <u>did not</u> trigger.[7]

With respect to SO_2, the Permittee has provided the following revised analysis. It includes comparison of emissions rates observed during the lookback period (2004-2008) for the pre-modification scenario with the emissions rates for period (2011-2018) for the post-modification scenario. Whether evaluating the emissions change on a maximum-to-maximum basis or average-to-average basis, the Table 4-7 below shows that the SO_2 emission rate has decreased in the post-modification period. DAQ believes that the applicant has utilized the correct methodology and appropriate data (actual fuel usage, sulfur content, and heating value for each fuel, emissions estimation factors for each fuel) to perform the analysis; thus, DAQ concludes that the NSPS modification under §60.14 did not trigger for SO_2.

Table 4-7: Final Analysis for SO_2

	Pre-modification		Post-modification		Net Change[1]	
	Maximum Monthly	Maximum Rolling 12-month Average	Maximum Monthly	Maximum Rolling 12-month Average	Maximum Monthly	Maximum Rolling 12-month Average
Pollutant	lb/million Btu	lb/million Btu	lb/million Btu	lb/million Btu	lb/million Btu	lb/million Btu
SO_2	1.35	1.29	1.14	1.09	-0.21	-0.20

[7] The applicant has indicated an average emission rate of 0.0023 lb/million Btu for PM for November 2006 stack test event. The DAQ believes that the correct, DAQ-approved average emission rate, for this event, is 0.005 lb/million Btu and not 0.0023 lb/million Btu.

[1] Net Change = Post-Modification Rate - Pre-Modification Emission Rate

In summary, based on the above, the DAQ concludes that the boilers are “modified” for PM only under NSPS Subpart Db; thus, it will include in the revised permit all applicable requirements for “modified” units in the context of this pollutant, as discussed below:

Emission Standards for PM

Each of the existing (modified) boilers shall comply with the following emission standards:

- When burning coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels, particulate emissions from these sources (ID Nos. ES-1-1A, ES-1-1B, and ES-1-1C) shall not exceed 0.030 lb/million Btu heat input (3-run stack test average), or 0.051 lb/million Btu heat input and 0.2 percent of combustion concentration (99.8 percent reduction) (3-run stack test average).

- When burning greater than 30 percent wood (by heat input) on an annual basis, particulate emissions from these sources (ID Nos. ES-1-1A, ES-1-1B, and ES-1-1C) shall not exceed 0.10 lb/million Btu heat input (3-run stack test average).

- Each source (ID Nos. ES-1-1A, ES-1-1B, and ES-1-1C) shall not cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (six-minute average), except for one six-minute period per hour of not more that 27 percent opacity.

- The PM including opacity standards shall apply at all times, except during periods of startup, shutdown, or malfunction.

Performance Testing

- The Permittee is required to conduct a performance test for PM emission standards above for boilers (ID No. ES-1-1A, ES-1-1B and ES-1-1C) in accordance with General Condition JJ, and §60.8 and §§60.46b(b) and (d), within 180 days of issuance of air quality permit 05856T21. The Permittee is also required to conduct any subsequent performance test, if requested by DAQ (or EPA), for PM emission standards, in accordance with General Condition JJ, and §60.8 and §§60.46b(b) and (d).

Monitoring

- Pursuant to §60.48b(a), the Permittee is required to calibrate, maintain, and operate a continuous monitoring system for measuring the opacity of emissions (COMS) discharged to the atmosphere and record the output of the system.

Recordkeeping

- Pursuant to §60.48b(b), (d), and (f), the Permittee is required to keep performance test data for PM emissions for each performance test, and records for the amounts of each fuel fired each day and opacity.

Reporting

- The Permittee shall submit a summary report of the monitoring and recordkeeping activities, including the information required pursuant to §§60.49b(h) and (i), postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December and July 30 of each calendar year for the preceding six-month period between January and June. All instances of deviations from the requirements of this permit must be clearly identified.

§60.15 Reconstruction

The applicant believes that it did not "reconstruct" the steam generating unit during the 2009 plant modification based on the NSPS General Provisions §60.15.

“Reconstruction" is defined under §60.15 as

> *"the replacement of components of an existing facility to such an extent that:*
>
> *(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, AND;*
>
> *(2) It is technologically and economically feasible to meet the applicable standards set forth in this part."*

"Fixed Capital Cost" is defined under §60.15 as *"capital needed to provide all depreciable components"*. The Preamble of the December 16, 1975 Amendments to the NSPS clarify that fixed capital costs include the costs of engineering, costs of purchase, and costs of installation of major process equipment, contractors fees, instrumentation, auxiliary facilities, buildings, and structures. The Preamble further indicates fixed capital cost does not include control equipment. A review of USEPA Applicability Determination Index (ADI) memos further shows the costs of land, site preparation, and demolition should not be considered in fixed capital costs.

The fixed capital costs related to the 2009 project were collected from post project financial review documents and are indicative of the actual dollars spent. The total 2009 project’s fixed capital costs at the Roxboro Facility are listed as $12,984,000, excluding material costs of the Mobotec system. Many of the listed engineering costs are related to the Mobotec control devices. However, CPI could not accurately dissociate the control device engineering costs from new fuel handling equipment engineering costs and have included all engineering costs for conservatism. For reference, the equipment and installation cost for the rotating opposed fire air (ROFA) and furnace sorbent injection (FSI) system were $6,056,000. All costs are in 2008 dollars.

The above fixed capital replacement cost includes the boiler building and equipment costs associated with the steam generating unit. This equipment includes the boilers, fuel loading conveyors, fuel bunkers, coal distributors, SS tubes, surface condenser, steam drums, forced draft fans, induced draft fans, waterwalls, superheaters, economizers, air heaters, wall-type soot blowers, feedwater system, ash removal equipment, piping steel frame & supports, catwalks, controls and electrical components. The fixed capital replacement cost does not include land, site preparation, demolition, boiler plant cranes, exhaust stacks, wood fuel handling equipment and scales, ash silos, baghouses, mobile equipment, station piping, water purification equipment and buildings, fire pumps, turbines, transformers, lab equipment, cooling towers and pumps, water-supply systems, security equipment, compressed air equipment, air cleaning and cooling apparata, cranes and hoists, railcar unloading equipment and buildings, wastewater treatment buildings, wastewater basins, lubricating systems, main exhaust and main steam piping.

CPI estimated the fixed capital replacement costs of a comparable new facility by reviewing appraisal reports used for insuring the plant. The most recent appraisal from 2015 estimated reproduction costs using the Cost of Reproduction New methodology. This is defined as the estimated amount required to reproduce a duplicate or a replica of the entire property at one time, in like kind and material, in accordance with current market prices for materials, labor, and manufactured equipment; contractors' overhead and profit; and fees, but without provision of overtime, bonuses for labor, or premiums for material or equipment. The estimated cost of replacement for the steam generating unit equipment and building is $112,603,000 in 2015 dollars. Adjusting the capital cost to 2008 dollars, the total replacement fixed capital cost is $116,365,000. Total costs were adjusted using the Chemical Engineering Plant Cost Index (CEPCI) from 2015 (556.8) and 2008 (575.4).

Based on this information, the 2008 project was approximately 11 percent of the total cost of a replacement boiler. CPI - Roxboro has relied on regulatory language in §60.15, the Preamble of the December 16, 1975 Amendments of the NSPS General Provisions (40 FR 58414-18), NSPS Subpart Db, NSPS Subpart Da, and the EPA's Applicability Determination Index (ADI) memos to determine if the 2009 project constituted "reconstruction" under the provision. The DAQ believes that the applicant has used the correct methodology, as discussed above, for the “reconstruction” analysis and agrees that the subject boilers (ID Nos. ES-1-1A, 1B, and 1C) are not reconstructed under §60.15.

15A NCAC 02D .0530 Prevention of Significant Deterioration

United States (US) Congress first established the New Source Review (NSR) program as a part of the 1977 Clean Air Act Amendments and modified the program in the 1990 amendments. The NSR program includes requirements for obtaining a pre-construction permit and satisfying all other preconstruction review requirements for major stationary sources and major modifications, before beginning actual construction for both attainment and non-attainment areas. The NSR program for attainment and non-attainment areas are called "Prevention of Significant Deterioration" (PSD) and "Non-attainment New Source Review" (NAA NSR), respectively. The NSR focuses on industrial facilities, both new and modified, that create large increases in the emissions of specific pollutants.

The basic goal for PSD is to ensure that the air quality in attainment areas (e.g., Person County NC for PM_{10}, $PM_{2.5}$, NO_2, SO_2, CO, ozone, and lead) does not significantly deteriorate while maintaining a margin for future industrial growth.

Under PSD, all major new or modified stationary sources of air pollutants as defined in §169 of the CAA must be reviewed and permitted, prior to construction, by EPA or the appropriate permitting authority, as applicable, in accordance with §165 of CAA. A "major stationary source" is defined as any one of 28 named source categories (e.g., "fossil fuel-fired steam electric plants of more than 250 million Btu per hour heat input"), which emits or has a potential to emit (PTE) of 100 tons per year of any "regulated NSR pollutant", or any other stationary source (i.e., other than 28 named source categories), which emits or has the potential to emit 250 tons per year of any "regulated NSR pollutant".

Pursuant to the Federal Register (FR) notice on February 23, 1982 (47 FR 7836), North Carolina (NC) has a full authority from the US Environmental Protection Agency (EPA) to implement the PSD regulations in the State effective May 25, 1982. NC's State Implementation Plan (SIP) - approved PSD regulation has been codified in 15A NCAC 02D .0530, which implements the requirements of 40 CFR 51.166 "Prevention of Significant Deterioration of Air Quality" with a few exceptions as included in the approved regulation. The version of the CFR incorporated in the NC's SIP regulation is that of July 1, 2014 and it does not include any subsequent amendments or editions to the referenced material. Refer to Table 1 to §52.1770 (at 40 CFR).

The CPI Roxboro facility is one of the listed 28 source categories source, classified under the category of "fossil-fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input." Therefore, the 100 tons/yr major stationary source classification applies. The facility is an existing major stationary source; because, it emits or has a potential to emit 250 tons per year or more of several regulated NSR pollutants: $PM_{10,}$ $PM_{2.5}$, SO_2, NO_x (as NO_2), CO, and VOC.

Because the existing facility is considered a major stationary source, any modification to an existing major source resulting in both significant emission increase and net significant emissions increase for a regulated NSR pollutant, is subject to PSD review and must meet appropriate review requirements.

Existing Major Stationary Source

Currently, the existing boilers (ID Nos. ES-1-1A, ES-1-1B, and ES-1-1C) are subject to the following BACT:

a. PM_{10} emissions from each boiler shall not exceed 0.027 pounds per million Btu heat input.
b. SO_2 emissions from each boiler shall not exceed 1.51 pounds per million Btu heat input.
c. NOx emissions from each boiler shall not exceed 0.55 pounds per million Btu heat input.
d. CO emissions from each boiler shall not exceed 0.55 pounds per million Btu heat input.
e. Sulfuric acid mist emissions from each source shall not exceed 0.021 pounds per million Btu heat input.
f. The maximum sulfur content of any coal received and burned in each boiler shall not exceed 1.0 percent by weight.

In addition, as an alternate, the Permittee is allowed to comply with only the emission limit of 1.51 lb/million Btu without the coal fuel sulfur limit of 1.0 percent by weight for SO_2 BACT, when using Mobotec's furnace sorbent injection system.

The current permit includes monitoring, record keeping and reporting requirements to demonstrate compliance with the above BACT for various pollutants. Specifically, the Permittee is required to comply with monitoring requirements, established for other applicable requirements in 02D .0501(c), .0516, and .0524, for PM10, SO_2, and sulfuric acid mist. For CO and NOx, the Permittee is required to measure emissions using a CEMS. Compliance with BACT for these pollutants shall be based on a 30-day rolling average basis. For the alternate SO_2 BACT when using FSI, compliance is to be determined using a 24-hour block average.

The above PSD requirements were mandated by the agency when the facility was initially permitted (1986-1987 circa) as a coal/natural gas/No. 2 fuel oil-fired electric power plant and they remain valid today. Thus, no changes to these requirements are justified.

Major Modification

With respect to the changes previously discussed (2009 project), the Permittee performed a PSD applicability analysis for determination of whether the project results in an emission increase of any regulated NSR pollutant above the applicable significance thresholds, using the "Actual-to-projected actual applicability test for projects that only involve existing emissions unit(s)" in §51.166(a)(7)(iv)(c) (as implemented through 02D .0530). The Permittee performed calculations for both baseline actual emissions (BAE), in accordance with 15A NCAC 02D .0530(b)(1), and projected actual emissions (PAE) in accordance with §51.166(b)(40) as below:

BAE

CPI Roxboro had submitted an air permit application in November 2008 for the approved 2009 project, which utilized plant operation from CY 2004 through CY 2007 to calculate BAE for the project, disregarding operation during 2008.

In this PSD application, CPI has revised those estimates (in 2008 application) by evaluating plant operation and pollutant emissions during each month from January 2004 through October 2008. The highest average emissions for each NSR pollutant during a consecutive 24-month period were determined. Pollutant emissions were estimated based on contemporaneous fuel usage data, fuel analysis, relevant stack testing data, and AP-42 and Electric Power Research Institute (EPRI) emission factors.

These initial estimates of BAEs have been revised, as required, to exclude any non-compliant emissions that occurred while the source was operating above any limitation the source was legally required to comply during the selected baseline period. During the selected baseline periods for various pollutants, the boilers were subject to PSD avoidance limits and were legally required to comply with limits of 61 tons/yr (PM_{10}), 1,212 tons/yr (NOx), 188.5 tons/yr (CO), and 3,282.8 tons/yr (SO_2). Thus, as per NCAC 15A 02D .0530(b)(l), the initial estimate of 203 tons/yr for CO has been adjusted to remove the non-compliant emissions (i.e., 203 tons - 188.5 tons = 14.5 tons); thus, the adjusted BAE for CO is 188.5 tons/yr. No other pollutants' emissions were required to be adjusted from the initial estimates.

Finally, the DAQ has evaluated whether there is any need for a downward adjustment to the initial estimate of BAE, especially, if the source would have exceeded an emission limitation which it must currently comply, pursuant to this NC's SIP-approved BAE definition in 02D .0530(b)(1). The DAQ has concluded that no further adjustments in the initial BAEs are needed for any regulated NSR pollutants.

The final BAE calculations, along with all supporting documentation, are included in the CPI submittal dated February 20, 2019. The following Table 4-8 includes baseline period for each regulated NSR pollutant and the adjusted BAEs for this modification application. These BAEs are utilized in estimating the change in emissions due to the project.

Table 4-8: Baseline Emissions and Baseline Period

Pollutant	BAEs Tons Per Year	Baseline Period
PM	25.4	August 2006 through July 2008
PM_{10}	23.7	August 2006 through July 2008
$PM_{2.5}$	22.3	August 2006 through July 2008
SO_2	1,809	August 2006 through July 2008
NO_2	538	January 2004 through December 2005
CO	188.5	July 2005 through June 2007

Pollutant	BAEs Tons Per Year	Baseline Period
VOC	6.6	January 2006 through December 2007
GHG as CO_2	288,051	August 2006 through July 2008
H_2SO_4 Mist	20.1	August 2006 through July 2008
F[8]	7.5	January 2004 through December 2005
Pb	0.0150	January 2006 through December 2007

The DAQ has verified the above BAEs, the supporting data, sources of information, and the underlying methodology, and found them acceptable.

PAE

CPI Roxboro calculated PAEs as defined in §51.166(b)(40)(i) with relevant portion copied below:

> *Projected actual emissions* means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant, and full utilization of the unit would result in a significant emissions increase, or a significant net emissions increase at the major stationary source.
>
> (ii) In determining the projected actual emissions under paragraph (b)(40)(i) of this section (before beginning actual construction), the owner or operator of the major stationary source:
> …
> (*c*) Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(47) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,
> …

As discussed earlier, this is a post-hoc PSD application for the previously approved 2009 project. This project did not increase the design capacity of any emission unit nor did it increase the PTE for any regulated NSR pollutants. Thus, as required, the Permittee has calculated annual emissions for each of the 5 years for the post-modification scenario, beginning 2011 and ending 2015, to determine the PAEs, using the contemporaneous fuel usage data, fuel analysis, contemporaneous emissions factors (both stack test and CEMS data), and AP-42 and EPRI emission factors.

With respect to excludable emissions, prior to the 2008 application, the CPI Roxboro facility combusted a blend of coal, TDF, and wood. Historical fuel usage and boiler utilization during the lookback period (January 2004 - October 2008) were evaluated to determine the maximum fuel usage which could have been accommodated during the baseline. Months in which, if a particular fuel (e.g. TDF) had the highest demonstrated usage compared to other months, that usage was annualized (x 12) to determine the maximum amount of the fuel which could be accommodated in a given year. The pollutant emissions resulting from the annualized fuel were then calculated based on contemporaneous fuel specifications during the month of highest usage. CPI Roxboro also analyzed the resulting annualized emissions to determine if any prior permit limits would have been exceeded, on both a short-term and long-term basis. CPI Roxboro also took into account any downtime which may occur due to ordinary maintenance.

The resulting maximum annualized emissions for each respective pollutant were then compared to the baseline emissions. It was determined that the net difference between the maximum annualized emissions and the baseline results

[8] Assumes all fluorides excluding HF.

in the amount of emissions the boilers could have accommodated prior to the modification. However, it should be noted that even if the boilers could accommodate a large amount of coal (or any other fuel) during the baseline, only the actual amount of fuel (and subsequent emissions) expected to be utilized after the project can be deducted from the projected actual emissions. In addition, any fuel usage post-project which is greater than the maximum demonstrated in the baseline is directly related to the project and cannot be excluded. In summary, any fuel usage and corresponding emissions, that are related to the project, are not allowed to be excluded from the emissions increase, even if the Permittee demonstrated that it could have accommodated a particular rate of fuel usage during the selected baseline period.

The DAQ believes that the Permittee has correctly determined the PAEs, in accordance with the EPA regulation and guidance[9]. The DAQ has accepted the methodology used and believes that the underlying data are representative.

Finally, it should be noted that the US Court of Appeals for the D. C. Circuit ("DC Circuit") has upheld the EPA's approach for excludable emissions as defined in PAE[10]. In addition, it is noteworthy to state here that the look-back period for any emissions unit, pursuant to DAQ's SIP-approved BAE definition in 02D .0530(b)(1), is more stringent than the look-back period in the court-upheld[11] federal definition of the same term in §51.166(b)(47).

Thus, based on baseline actual to projected actual applicability test, the DAQ concludes and agrees with the applicant that the previously approved 2009 project triggered major modification under PSD for CO only. The following Table 4-9 includes the PSD applicability analysis, showing the step-by-step procedure. It needs to be noted that the Table below includes emissions data for PAE for 2015, as this year had the maximum emissions for various pollutants for the post-modification period (2011-2015).

Table 4-9: PSD Applicability Analysis

	Regulated NSR Pollutant Emissions Tons/Year										
	PM	**PM_{10}**	**$PM_{2.5}$**	**NO_2**	**CO**	**GHG as CO_2**	**SO_2**	**VOC**	**H_2SO_4**	**F[1]**	**Pb**
Unadjusted Actual Boiler Emissions	36	30	30	409	728	311,267	2,006	9.6	22.2	5.6	0.044
Project Related Ancillary Equipment Emissions	2.3	0.7	0.2	-	-	-	-	-	-	-	-
Total Unadjusted Emissions due to Project[2]	37.8	31.0	30.1	408.8	728	311,267	2,006	9.6	22.2	5.6	0.044
Baseline Actual Emissions[3]	25.4	23.7	22.3	538	188.5	288,051	1,809	6.6	20.1	7.5	0.015
Change in Emissions, Unadjusted for Demand Growth Exclusion	12.4	7.3	7.8	-129.2	539.3	23216.4	196.9	3.0	2.1	-1.87	0.03
Significant Emission Rate	**25**	**15**	**10**	**40**	**100**	**75,000**	**40**	**40**	**7.00**	**3**	**0.6**
Emissions Which Could Be Accommodated Prior to Project[4]	14.5	13.1	12.2	-	-	85,386	665	-	7.1	-	-

[9] 67 FR 80186 (December 2012), at 80196 and 80203.
[10] Page 51 (Slip Opinion), *State of New York, et al., v. U.S. Environmental Protection Agency*, No. 02-1387, Decided June 24, 2005.
[11] Page 47 (Slip Opinion), Id. at 8.

	Regulated NSR Pollutant Emissions Tons/Year										
	PM	**PM_{10}**	**$PM_{2.5}$**	**NO_2**	**CO**	**GHG as CO_2**	**SO_2**	**VOC**	**H_2SO_4**	**F[1]**	**Pb**
Adjusted Actual Emissions Due to Project	23.3	17.9	17.9	408.8	727.8	225881.3	1341.2	9.6	15.0	5.6	0.0
Adjusted Projected Emission Increase	-2.1	-5.8	-4.3	-129.2	539.3	-62169.4	-467.9	3.0	-5.0	-1.9	0.0
Significant Emission Rate	**25**	**15**	**10**	**40**	**100**	**75,000**	**40**	**40**	**7**	**3**	**0.6**
Major Modification?	No	No	No	No	**Yes**	No	No	No	No	No	No

1. Assuming all fluorides as F^- and not HF.

2. Emissions are prior to excluding emissions which could be accommodated and are unrelated to the project when comparing to thresholds.

3. Estimates for BAE were calculated based on the highest 24-month average emissions which occur during the baseline. Emissions estimates for each month in the baseline are provided in a separate calculation sheet (Refer to application). Only boiler emissions are included and emissions of any other sources are not accounted, providing a conservative approach.

4. Estimates for excludable emissions due to demand growth for each year after the project are included in a separate calculation sheet (Refer to application).

It should be noted that both BAEs and PAEs above include emissions associated with startup, shutdown, and malfunction events. In addition, the BAEs do not include any pre-project particulate emissions from non-boiler sources, such as fugitive emissions resulting from fuel and ash handling. However, all quantifiable fugitive emissions have been incorporated in PAEs to the extent quantifiable. By not including fugitive emissions in the BAEs, the DAQ agrees with the Permittee that the project change calculus becomes conservative. Finally, in addition to PM_{10} and $PM_{2.5}$, for PM emissions, the Permittee has incorporated condensable portion as well in both BAE and PAE, as required pursuant to NC's SIP-approved regulation in 15A NCAC 02D .2609(a).

CPI is required and has performed the following reviews and analyses for emissions of CO for the 2009 project. These reviews and analyses are required for each affected new or modified emission unit causing or contributing to an emission increase of any regulated NSR pollutant equaling or exceeding its significance threshold, as per 15A NCAC 02D .0530.

- BACT analysis
- Air quality analysis
- Source impact analysis
- Additional impact analysis
- Class I analysis (Not applicable)

15A NCAC 02D .0530(u) Use of Projected Actual Emissions to Avoid Applicability of Prevention of Significant Deterioration

As discussed extensively above, pursuant to this provision, the previously approved 2009 project resulted in DAQ including in the permit requirements for monitoring, record keeping and reporting of emissions for various pollutants. Refer to air quality permit 05856T10, March 31, 2009. The first annual report for calendar year 2015 exhibited an increase in emissions of CO, exceeding well over its significance threshold. Thus, the Permittee was required to obtain a PSD permit for the above refenced project. In summary, the existing requirement in 02D .0530(u) will be supplanted with the requirements in 02D .0530 in the revised permit.

15A NCAC 02D .0614 Compliance Assurance Monitoring

With respect to the CAM (Compliance Assurance Monitoring) regulation applicability for the previously approved control devices (ROFA, SNCR, and FSI in the 2009 project), the DAQ had earlier addressed the CAM applicability

(05856Tl6, 12/18/2014) and concluded that because the Permittee uses the CEMS for both NOx and SO_2 to comply with some existing requirements applicable to the boilers, considered as continuous compliance determination method (CCDM) per Part 64 (40 CFR), this regulation does not apply with respect to the above control technologies. Moreover, the ROFA is considered a combustion feature, not an active control device, which is another reason that CAM cannot be required for ROFA.

The current permit includes a CAM plan for the existing baghouses, which are not part of the 2009 project. The plan includes visible emissions and pressure drop as indicators for compliance assurance. The permit defines excursions and quality improvement plan for each parameter. Finally, the permit includes all applicable reporting requirements pursuant to Part 64.

15A NCAC 02D .1109 112(j) Case-by-Case Maximum Achievable Control Technology

The current permit in Section 2.1.A.7 includes emission standards, testing, monitoring, recordkeeping, and reporting, pursuant to 02D .1109 (§112(j) of CAA). These §112(j) requirements for the facility boilers have sun-set on May 19, 2019. The boilers are required to comply with the applicable requirements in 5D MACT (40 CFR 63), starting May 20, 2019, as included in Section 2.1.A.10 of the current permit, as below. Thus, the inapplicable requirements in 02D .1109 will be removed from the permit.

15A NCAC 02D .1111 "Maximum Achievable Control Technology"

As stated earlier, the existing boilers will be subject to this requirement (5D MACT) beginning May 20, 2019. The current permit includes all applicable requirements with respect to emission standards, work practice standards, operating limits, notification, initial compliance, subsequent compliance, energy assessment, recordkeeping, and reporting.

The following emissions limits shall apply:

Pollutant	**Emission Limit**
Hydrochloric Acid (HCl)	2.2E-02 lb per MMBtu of heat input
Mercury (Hg)	5.7E-06 lb per MMBtu of heat input
Carbon Monoxide (CO)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)
Filterable Particulate Matter (PM) or Total Suspended Metals (TSM)	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)

The following operating limits shall apply:

Maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average);

or

Install and operate a bag leak detection system according to §63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.

For boilers and process heaters that demonstrate compliance with a performance test, the Permittee shall maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.

The Permittee is required to conduct a tune-up of the existing boilers every year.

The Permittee is also required to conduct a one-time energy assessment.

The permit includes all applicable record keeping and reporting requirements pursuant to 5D NESHAP.

Cross-State Air Pollution Rule (CSAPR) Requirements

The first legally-survived[12] "transport rule", pursuant to the "good neighbor" provision in CAA §110(a)(2)(D)(i), covers the down-wind states for non-attainment and maintenance of 1997 ozone and $PM_{2.5}$ NAAQSs, and 2006 $PM_{2.5}$ NAAQS. This regulation includes ozone season and annual NOx requirements, and annual SO_2 requirements, for power sector electric generating units in various eastern USA (total 28 states). The transport rule is also called the Cross-State Air Pollution Rule (CSAPR). The requirements are codified in 40 CFR 97, Subparts AAAAA, BBBBB, and CCCCC. It needs to be stated that these requirements are federal enforceable only. The current permit includes the above CSAPR requirements.

Finally, it should be stated that the EPA has also issued a CSAPR Update rule for ozone season NOx, covering the 2008 ozone NAAQS for the 22 states, mainly eastern and mid-western states. This regulation (again a FIP) does not apply to NC.

NCGS 62-133.8(g) Control of Emissions (Senate Bill 3 Best Available Control Technology)

The Permittee is required to comply with the following state enforceable only BACT under Senate Bill 3 (Session Law 2007-397):

1. PM_{10} emissions shall not exceed 0.027 pounds per million Btu heat input per boiler.
   (*Stack test: 3-run average for both filterable and condensable*)

2. Nitrogen oxide emissions shall not exceed 0.55 pounds per million Btu heat input per boiler[6].
   (*CEMS: 30-day rolling average)*

3. Carbon monoxide emissions shall not exceed 0.55 pounds per million Btu heat input per boiler. *(CEMS: 30-day rolling average)*

4. Sulfuric acid mist emissions shall not exceed 0.021 pounds per million Btu heat input per boiler.

5. Sulfur dioxide emissions shall not exceed 1.51 pounds per million Btu heat input per boiler when burning tire derived fuel (TDF). *(CEMS: 30-day rolling average)*

6. Inherently low sulfur biomass/wood shall be burned in the boilers.

7. Volatile organic compounds emissions from the biomass-fired boilers shall be minimized by utilizing Good Combustion Practices.

8. Mercury emissions shall not exceed 5.00 E-6 pounds per million Btu heat input per boiler.
   (Stack test: 3-run average).

The current permit also includes monitoring, recordkeeping, and reporting requirements.

5.0 BACT Analysis

Background

As per CAA §169(3):

[12] *EPA v. EME Homer City Generation L.P.*, Supreme Court of the United States, April 29, 2014.

> “The term "best available control technology" means an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act. Emissions from any source utilizing clean fuels, or any other means, to comply with this paragraph shall not be allowed to increase above levels that would have been required under this paragraph as it existed prior to enactment of the federal Clean Air Act Amendments of 1990.”

Given the variation between emission sources, facility configuration, local air-sheds, and other case-by-case considerations, Congress determined that it was impossible to establish a single BACT determination for a particular pollutant or source. Economic, energy, and environmental impacts are mandated in the CAA to be considered in the determination of case-by-case BACT for specific emission sources. In most instances, BACT may be defined through an emission limitation. In cases where this is impracticable, BACT can be defined using a particular type of control device, work practice, or fuel type. In no event, can a technology be recommended which would not comply with any applicable standard of performance under CAA §§111 (NSPS) or 112 (NESHAP).

The EPA developed guidance, commonly referred to as “Top-Down” BACT[13], for PSD applicants for determining BACT. This guidance is a non-binding reference material for permitting agencies, which process PSD applications pursuant to their SIP-approved regulations. As stated in Section 4.0 above, NCDAQ issues PSD permits in accordance with its SIP-approved regulation in 15A NCAC .02D .0530. Therefore, the DAQ does not strictly adhere to EPA's “top-down” guidance. Rather, it implements BACT in accordance with the statutory and regulatory language. As such, NCDAQ's BACT conclusions may differ from those of the EPA.

As stated above, a major modification review is triggered for the 2009 project due to increases in emissions of CO. Thus, each emissions unit undergoing physical or operation change (such as three existing boilers) where the net emissions increase for CO is projected to occur, is required to apply BACT for this pollutant, as per §51.166(j)(3).

The emissions unit must be defined so that the BACT analysis can be performed. In this case, the purpose of the previously approved 2009 project was to increase the permitted amounts of fuel burning (heat input basis) for both TDF and wood in the existing coal/TDF/wood-fired boilers by installing fuel handling and storage equipment and pollution control devices in the form of ROFA and FSI. The intent of the project was to reduce the NOx and SO_2 emissions while increasing the fuel usage for both TDF and wood. It should be emphasized that the project’s objectives were not to eliminate the existing coal firing capability. Thus, it is clear that the emissions unit is each existing boiler, burning a mixture of coal/TDF/wood and proposed for increasing the amounts of wood and TDF burning. None of the other emissions unit (new or modified) with respect to material handling and storage equipment, as above, have any association with the project’s CO emissions; hence, they are excluded from the BACT analysis.

Finally, as previously stated in Section 2.2 above, although the existing boilers have a permission to burn natural gas, No. 2 and No. 4 fuel oils, pelletized paper, and fly ash briquettes, no infrastructure exists to burn fuel oils or natural gas. Further, also stated in the referred section, for pelletized paper and fly ash briquettes, additional modifications to existing material handling and fuel storage areas must occur in order for the facility to consistently burn any of these alternative fuels.

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[13] “Improving New Source Review (NSR) Implementation”, J. Craig Potter, Assistant Administrator for Air and Radiation US EPA, Washington D.C., December 1, 1987, and “Transmittal of Background Statement on “Top-Down” Best Available Control Technology”, John Calcagni, Director, Air Quality Management Division, US EPA, OAQPS, RTP, NC, June 13, 1989.

Therefore, DAQ believes that the emissions unit for the project is accurately defined as above.

RBLC Data

When establishing BACT for pollutant triggered (CO) for the proposed modification, BACT determinations of similar stoker boilers have been reviewed and taken into consideration. Specifically, the DAQ has reviewed the RBLC data for time-period (2008-present) for coal/wood/TDF-fired electricity generating units with heat input rate exceeding 100 million Btu/hr. DAQ believes that this data provides the relevant information on BACT determinations from various permitting authorities in recent years to help determine the type of technology and/or associated limitation for units with a similar design. The Permittee has also reviewed the same database for almost the same period (2007 through 2017) for the stoker boilers.

BACT Analysis for CO

Carbon monoxide emissions result due to incomplete combustion of carbonaceous material in fuel. The formation of CO is a by-product of the combustion process in which carbon is not fully oxidized to carbon dioxide. Generally, higher CO concentrations in exhaust gas indicate a loss in boiler efficiency. It is desirable to minimize CO emissions in order to increase boiler efficiency and reduce total fuel use. CO emissions can be controlled by both pre-combustion and post-combustion technologies. The available control options for CO include catalytic oxidation, thermal oxidation, and good combustion practices.

Catalytic Oxidation

An oxidation catalyst is a post-combustion technology that removes CO from the exhaust gas stream after it is formed in the electric utility boiler. In the presence of a catalyst, CO will react with oxygen present in the boiler exhaust, converting it to carbon dioxide. No supplementary reactant is used in conjunction with an oxidation catalyst. Technical factors relating to this technology include the catalyst reactor design, optimum operating temperature, back pressure loss to the system, catalyst life, and potential collateral increases in emissions of PM10 and sulfuric acid mist emissions.

A catalytic oxidizer converts the CO in combustion gases to carbon dioxide (CO_2) at temperatures ranging from 500 ºF to 700 ºF in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst. Catalyst poisoning can be minimized if the catalytic oxidizer is placed downstream of a particulate matter control device. The baghouses at CPI Roxboro generally operate at temperatures less than 350 ºF; therefore, utilization of catalytic oxidation would require reheating the exhaust gases from the baghouse to the operating temperature for the catalytic process. This reheating process has been proposed at some biomass-fired boilers, however, no successful completion of oxidation technology has been implemented / demonstrated in practice on biomass boilers as per the Permittee. In addition, the Permittee states that no coal and TDF-fired units have or are known to have, RCO installed and successfully operated.

The CPI Roxboro facility plans to continue combusting TDF and coal in their boilers. Unlike biomass, coal and TDF have relatively high concentrations of elemental sulfur. For example, for 2017, coal and TDF had an average sulfur concentration of 0.79 and 1.30 weight percent, respectively. The elemental sulfur in coal and TDF results in significant emissions of SO_2 during combustion. An oxidation catalyst not only oxidizes CO in the flue gas to produce CO_2, but, also oxidizes SO_2 to create sulfur trioxide (SO_3) and sulfuric acid mist (H_2SO_4 - SAM). The high levels of SAM can lead to rapid and destructive corrosion of ducts and equipment downstream of the catalyst. The high levels of SO_3 can also lead to high levels of opacity and visible blue smoke from the stack. The Permittee has stated that currently there is no control technology available to reduce SO_2 concentrations in the exhaust to low enough levels to mitigate SAM formation.

Catalytic oxidation is therefore deemed to be technically infeasible for existing coal/biomass/TDF-fired, spreader stoker boilers at CPI Roxboro; thus, it has been eliminated for further evaluation.

Thermal Oxidation

Thermal oxidation can be used to oxidize CO to carbon dioxide and water by passing exhaust gas through a burner flame zone to combust remaining carbon compounds. Thermal oxidizers typically operate at temperatures of 1,500°F or higher to achieve control efficiencies of up to 95 percent or higher.

Even if the thermal oxidizer is placed before the existing particulate emission control device to reduce the need for reheating of exhaust gases, it would still require a significant amount of energy to lift the exhaust temperature to the operating temperature of a thermal oxidizer as stated above. That will generate additional undesirable increases in emissions of various combustion gases (for example, NO_X and CO_2). In addition, as stated above, due to the high amount of sulfur in both coal and TDF, the oxidizer is expected to covert SO_2 to SO_3 and sulfuric acid mist. The formation of sulfuric acid mist can also create serious maintenance issues for ductwork or any downstream control devices.

For the above reasons, the use of thermal oxidation has been concluded a technically infeasible option for coal/TDF/wood fired boilers at CPI Roxboro.

Good Combustion Control Practices (GCP)

As discussed earlier, CO emissions are the by-product of incomplete combustion of carbonaceous fuels. CO emissions can be minimized with proper boiler design and good combustion practices (GCP). Some typical GCPs include the following:

- Adequate excess air,
- Adequate fuel and air mixing (turbulence),
- Sufficient combustion temperatures,
- Adequate residence time.

Utilizing GCP will maximize the conversion of carbonaceous fuel to CO_2, instead of CO and will increase the rate of fuel-to-energy output from the boilers.

Good combustion control is deemed a technically feasible option for controlling CO emissions from coal/biomass/TDF fired boilers at CPI facility.

Energy, Environmental, and Economic Impacts

There are no adverse impacts associated with respect to statutory energy, environmental, and economic impacts criteria, for use of good combustion control practices.

BACT Determination

The DAQ review of the RBLC data indicates a total of 9 determinations for the chosen period of 2008-2018, which have stoker boiler design with wood firing permission and heat input rate greater than 100 million Btu/hour. No stoker boiler with coal or TDF firing has been identified in the search. Out of these 9 determinations, 8 of them include use of good combustion control practices and/or over-fire air as control method and only 1 indicates the use of an oxidation catalyst. With respect to the determination with the use of oxidation catalyst, it needs to be noted that, as permitted, the facility never retrofitted the existing natural gas/No. 6 fuel oil-fired electric generating unit to burn biomass and install an oxidation catalyst for CO BACT; thus, the permitting authority rescinded the associated NSR permit[14]. Therefore, the determination consisting of oxidation catalyst will not be further considered. Finally, the BACT for the stoker biomass-fired only boilers for the remaining 8 determinations range between 0.075 lb/million Btu and 0.45 lb/million Btu/hour with majority (6) of them include 30-day rolling average.

[14] RBLC ID CT-0156 for Montvale Power LLC. Email communication between Rahul Thaker, NCDAQ, and Jaimeson Sinclair, Director, Engineering Division, Bureau of Air Management, Connecticut Department of Energy and Environmental Protection, 3/22/2019.

At the outset, it needs to be stated that the above RBLC determinations are for firing biomass only, unlike fuel mixture of wood, TDF, and coal, in CPI Roxboro boilers.

DAQ understands that based upon the most recent calendar year (2018)'s 30-day rolling average CO continuous emissions data for the facility boilers, as provided by the Permittee, the actual CO emissions vary between 0.216 to 0.598 lb/million Btu (sample size of 338). The average and median values for CO emissions for the sample are 0.40 lb/million Btu and 0.41 lb/million Btu, respectively. Similarly, the 25^{th} percentile and 75^{th} percentile are 0.355 lb/million Btu and 0.446 lb/million Btu, respectively. DAQ believes that this wide range in actual emissions exhibits a significant variability in CO emissions throughout the year.

As stated previously, CO is formed due to the incomplete combustion of carbonaceous material in fuel. Excess CO formation is generally detected when not enough oxygen is available to complete the combustion reaction. Thus, the supply of air and the distribution of fuel are two key variables which dictate the extent of combustion.

Stoichiometrically, the forced draft (FD) fan(s) supply enough excess air to the grate area to support complete combustion. The Permittee contends that the induced draft (ID) fans at the facility are original to the boiler design for coal firing and can only handle a fixed amount of flue gas. In addition, the existing boilers are equipped with ROFA as part of the 2009 project. The ROFA technology, designed to reduce NO_x emissions, also helps reduce CO formation by promoting enhanced combustion throughout the primary, middle and upper furnace.

Therefore, the Permittee believes that optimizing fuel distribution in the furnace of a spreader stoker boiler is the best way to reduce CO and optimize efficiency of the unit. However, the facility contends that the fuel mix and fuel application in the grate area of the boilers is much different than a stoker boiler combusting a single fuel at any other facility, such as boilers in RBLC determinations as discussed above. Moreover, per the Permittee, the mix of coal, TDF and biomass fuel adds complexity because the mixing/distribution of fuel and air is not matched by an even energy density in the coal, TDF, and biomass fuel. The DAQ does believe that in general, burning of mixture of fuels such as coal, TDF, and wood) can make the boiler operation more difficult than at a biomass only facility.

With respect to three specific determinations (VA-0316, VA-0317, and VA-0318)[15], identified in the RBLC database search, the Permittee states that they are most closely related to the Roxboro design and have demonstrated compliance. However, each of these units are biomass only fired power plants equipped with enhanced over-fire air (OFA) systems. Again, the Permittee contends that biomass only stoker-fired boilers have the advantage of a single fuel and can achieve much greater control of fuel mixing and distribution of fuel onto the furnace grates, decreasing CO formation.

Thus, CPI concludes that the achieving emission limits as included in the approved BACTs for various biomass-only stoker boilers in the RBLC database are not technically feasible for the CPI Roxboro's multi-fuel firing facility. Finally, with respect to achieving lower limits, if technically feasible, CPI states that increasing the secondary over-fire air in amounts greater than presently done could result in potentially unsafe operating conditions in the boiler and at the baghouse.

Thus, for Roxboro boilers, for burning a mixture of coal/TDF/wood, CPI proposes a BACT of 0.55 lb/million Btu, as a 30-day rolling average, for all periods of operation including start-up and shut-down. The Permittee believes that it is an achievable limit that has been safely demonstrated for a longer duration while the boilers have operated with current fuel blends under good combustion practices. The Permittee is to employ the following good combustion control practices:

- Maintains enough airflow across the grates to ensure adequate excess air,

- Maximizes fuel distribution across the grates to ensure adequate fuel and air mixing,

- Provides secondary air to the furnace to provide enough oxygen to complete combustion of CO,

[15] Virginia Electric and Power Company's Hopewell, Altavista, and Southampton Power Station plants.

- Utilizes existing ROFA mixing system to promote good furnace temperature profile and adequate time to burn out char.

DAQ agrees that biomass only determinations for stoker boilers in EPA's RBLC search do not provide the relevant information on what level of emissions reduction may be achievable for a multi-fuel fired stoker boilers at CPI boilers over the life of the equipment. The DAQ has carefully considered the technical issues discussed above with regard to limitations on providing adequate amount of combustion air and controlling boiler process in a multi-fuel environment, and creation of possible unsafe operating conditions in boiler and baghouse, if secondary air is to be increased more than the currently used. The DAQ believes that these factors do contribute to the Permittee's ability to achieve lower CO emissions continuously over the life of the equipment when a mixture of fuels (such as coal/TDF/wood) are burned.

The DAQ has also considered the variability in actual emissions for the facility boilers over a longer period as noted above. With regard to variability in emissions, the EPA's Environmental Appeals Board (EAB) has recognized that it would be erroneous to set a BACT without determining that "the proposed facility can demonstrate compliance with [the limit] under all operational circumstances".[16] Moreover, this Board has stated that the BACT needs to be established by incorporating "sufficient margin over actual operational data to avoid continual compliance difficulties".[17] Finally, the EAB "has recognized that permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis."[18]

Moreover, with respect to "achievable" criterion in both statutory and regulatory BACT definition, the court had said that "where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur.""[19]

Thus, after deliberation, the DAQ proposes a CO BACT for the existing boilers of 0.55 lb/million Btu on a 30-day rolling average basis, using good combustion control practices. This DAQ-proposed BACT is approximately 34 percent above the median CO emission rate of 0.41 lb/million Btu exhibited in 2018, capturing variability in boiler emissions and most adverse conditions such as startup and shutdown, accounting for a reasonable safety factor (1.34), and avoiding continual compliance difficulties in meeting the BACT. The DAQ further believes that the above level of BACT will allow the source to comply on a consistent basis over the life of its boiler operations, as demonstrated by 2018 CO CEMS data (30-day rolling average) for facility boilers[20].

The DAQ-proposed BACT applies during all periods of operation, including startup, shutdown, and malfunction periods. Compliance is to be to be achieved using a CEMS.

It should be emphasized that this proposed CO BACT is at least as stringent as the applicable SIP limit (0.55 lb/million Btu with a 30-day rolling average basis under the current PSD limitation) and Part 63 standards (0.675 lb/million Btu under §112(d) MACT equating to 720 ppmvd @ 3% O_2 with a 30-day rolling average basis)[21], thus, complying with both statutory and regulatory requirements in setting BACT.

BACT Summary

The following (Table 5-1) summarizes the DAQ proposed BACT for the existing coal/TSD/wood-fired electric generating units (ID Nos. ES-1-1A, ES-1-1B, and ES-1-1C):

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[16] *In Re Three Mountain Power LLC*, 10 E.A.D. 53 (EAB 2001).
[17] Page 53, Id. at 14.
[18] *In Re. Masonite Corp.*, 5 E.A.D. 551, 560-561 (EAB 1994), *In Re Knauf Fiber Glass GmbH*, 9 E.A.D. 1,15 (EAB 2000).
[19] *Sierra Club v. EPA*, No. 97-1686, US Court of Appeals for the D.C. Circuit, Decided March 2, 1999 (citing *National Lime Association v. EPA*, No. 78-1385, Decided May 19, 1980, 627 F.2d 416).
[20] Operating 96 percent of period (2018) at or below the proposed level of BACT.
[21] Applicable effective 5/20/2019.

Table 5-1: BACT Summary

EMISSION SOURCE	POLLUTANT	BACT	CONTROL DESCRIPTION
Boilers (ID Nos. ES-1-1A., ES-1-1B, and ES-1-1C)	CO	0.55 lb/million Btu, 30 day rolling average (includes normal, startup, shutdown, and malfunction)	Good combustion control

6.0 Air Quality Analysis

§51.66(m)(1) requires that the major modification application for a PSD permit include an analysis of the ambient air quality of the area where the source is located for any regulated NSR pollutant exceeding the significant net emissions increase. This analysis is called “pre-application analysis” (generally called the “preconstruction monitoring” requirement). For pollutants with associated NAAQS, the application must include 1 year of continuous monitoring data from the date of the receipt of the complete application. The permitting agency may accept ambient monitoring data for a shorter duration, but data cannot be for less than 4 months. For pollutants for which no NAAQS exist, the permitting authority can require an analysis containing such data as it determines appropriate to assess the ambient air quality in the area in which the source is located.

§51.66(m)(2) includes that the owner or operator of a major modification shall after construction of such modification, conduct such ambient monitoring as the permitting authority determines, that is necessary to determine the effect emissions from the stationary source or modification may have or are having on air quality in any area. This monitoring is called “post-construction monitoring”.

However, §51.166(i)(5) includes that permitting authority may exempt any major modification from the requirements of §51.166(m), with respect to monitoring for a specific pollutant, if net emissions increase of the pollutant from a modification would cause, in any area, air quality impacts less than the following amounts:

Carbon monoxide - 575 ug/m^3, 8-hour average;
Nitrogen dioxide - 14 ug/m^3, annual average;
$PM_{2.5}$ - 0 µg/m^3, 24-hour average;
PM_{10} -10 µg/m^3, 24-hour average;
Sulfur dioxide - 13 ug/m^3, 24-hour average;
Lead - 0.1 µg/m^3, 3-month average.
Fluorides - 0.25 µg/m^3, 24-hour average;
Total reduced sulfur - 10 µg/m^3, 1-hour average
Hydrogen sulfide - 0.2 µg/m^3, 1-hour average; and
Reduced sulfur compounds - 10 µg/m^3, 1-hour average

The above concentration values are called “significant monitoring concentrations (SMC)”.

In addition, for ozone, no *de minimis* air quality level (i.e., SMC) has been provided. As per EPA, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data.

The same provision includes some more exemptions from this air quality analysis requirement (both “preconstruction monitoring” and “post-construction monitoring”) for the source (i.e., applicant) as follows: (i) If any regulated NSR pollutant is not listed with the associated impact level (i.e., SMC), or (ii) the concentrations of the pollutant in the area that the major modification would affect is less than the associated SMC.

As stated above, this major modification review is for emissions of CO only. As discussed below in Section 7.0, the predicted air quality impact of CO is less than the applicable SMC. Hence, no ambient monitoring (both pre- and post-construction) for CO may be required for this major modification.

7.0 Source Impact Analysis

A preliminary analysis was conducted only for CO, given that project emission increases were below the applicable significant emission rates for the other PSD pollutants with Class II Area Significant Impact Levels (SIL). The modeling results were compared to the applicable Class II Area SIL to determine if a full impact analysis would be required for that pollutant. AERSCREEN (v 16216) for rural land-use, elevated terrain, automated receptors and building downwash, was used to model the five levels of air emissions from Unit 1 boilers. Stack parameters and emission rates used in the modeling are included below in Tables 7-1 and 7-2 below. The results of the modeling for the maximum impacts of the modification's HlH (i.e., highest among each individual year's maximum value for five years) 1-hour and 8-hour averaging time air concentrations are shown in Table 7-3 below.

Table 7-1: Boiler Stack Parameters

Load	Stack Height	Stack Diameter	Exhaust Flow Rate	Exhaust Velocity	Exhaust Temperature
	feet	feet	ACFM	fps	ºF
100%	198	8.75	262,959	72.9	350
75%	198	8.75	197,219	70.4	350
50%	198	8.75	131480	63.8	350

Table 7-2: Modeled CO Emission Rates

Load	Nominal Heat Input	CO BACT Limit	Potential Emissions, 1-hour and 8-hour Averaging Periods	Baseline Emissions ,1-hour and 8-hour Averaging Periods[22]	Modeled Emission Rates
	million Btu/hr	lb/million Btu	lb/hr	lb/hr	lb/hr
100%	660	0.55	363	43.04	320
75%[23]			363		320
50%[24]			363		320
Short Term Spike (Higher Load)			1,200		1,157
Short Term Spike Startup & Shutdown			600		557

Table 7-3: Class II Significant Impact Results

	Averaging Period	Maximum Impact (µg/m^3)					Class II Significant Impact Levels
		100% Load	75% Load	50% Load	Short Term Maximum	Short Term Startup & Shutdown	µg/m^3
Net Change	One-Hour	131.5	149.1	194.6	539.1	364.9	2,000
	Eight-Hour	118.4	134.2	175.2	485.2	328.4	500

As shown above in Table xx, the NAAQS and Class II Area PSD increment analysis for CO are not required, because the predicted impacts are below the applicable 1-hour and 8-hour SILs.

8.0 Additional Impact Analysis

[22] The highest two-year average adjusted baseline CO emissions are 188.5 tons per year. Short-term CO emissions are estimated to be 188.5 tpy x 2,000 lbs/ton x (1 year / 8,760 hours) = 43.04 lbs/hr.
[23] The applicant conservatively analyzes (models) the worst-case mass emission rate at 100 percent load for 75 percent and 50 percent load stack conditions.
[24] Id. at 23.

Additional impact analyses are conducted for growth, soils and vegetation, and visibility impairment.

Growth Impact

The CPI Roxboro plant is an existing facility and only a small number of temporary construction jobs to install the equipment are expected. Therefore, this project is not expected to cause a significant increase in growth in the area.

Soils and Vegetation

Because no pollutant exceeded the SILs, no soils and vegetation analysis was necessary.

Class II Visibility Impairment Analysis

The Class II visibility analysis was not required given the project emissions do not include significant amounts of visibility-impairing pollutants, such as NOx, SO_2, $PM_{2.5}$, or PM_{10}. Additionally, the project is not located within 10 km of an area protected from visibility impairment. Therefore, NC DAQ did not require the Class II Visibility Impairment Analysis from the applicant.

9.0 Class I Increment/Air Quality Related Values (AQRV) Regional Haze Impact and Deposition Analyses

The Federal Land Managers for the Class I areas within 300 km of CPI Roxboro were contacted and none of them required any analysis; thus, no analysis was conducted.

Class I Area Significant Impact Level Analysis

A Class I Area significant impact screening analysis was not required because project emission increases were below the respective significant emission rates for regulated NSR pollutants with established Class I Increments.

Class I Increment/Air Quality Related Values (AQRV) Regional Haze Impact and Deposition Analyses

The project does not include significant emissions of any pollutant with an established Class I Area Increment or Deposition Analysis Threshold. The project also does not include significant emissions of any visibility-impairing pollutant such as NOx, SO_2, $PM_{2.5}$, or PM_{10}. Therefore, analysis of project impacts on Class I Area Increments, deposition or visibility, was not required.

10.0 Facility Wide Air Toxics

The existing boilers are exempt from NC's air toxics program pursuant to 02Q .0702(a)(27). Specifically, the boilers are currently subject to §112(d) MACT (5D NESHAP). Thus, these boilers will remain exempt. During the issuance of the Title V permit 05856T16 (12/18/2014), the DAQ determined that "unacceptable risk to human health" does not exist even if the air toxics emissions are not permitted. None of the modifications discussed in this application review will change this prior conclusion.

11.0 Facility Emissions Review

The first page of this application review includes facility-wide actual emissions, as reported to DAQ for calendar year 2013-2017.

12.0 Public Notice/EPA and Affected State(s) Review

This permit application processing is conforming to the public participation requirements, pursuant to both 15A NCAC 02D .0530 "Prevention of Significant Deterioration" and 15A NCAC 02Q .0500 "Title V Procedures".

Satisfying the PSD requirements, a public notice (See Appendix B) for the availability of the preliminary determination and the draft Title V will be published in a local newspaper of general circulation for 30 days for review and comments on xx. A copy of the public notice will be provided to the EPA, and all local and state authorities having authority over the location at which the proposed modification is to be constructed. Finally, all documents will be placed on the DEQ website and a complete administrative record for the draft permit documents will be kept for public review at the DEQ's Raleigh Regional Office for the entire public notice period (30 days). Appendix C includes listing of both the entities and the documents to be sent to each listed entity for the proposed PSD major modification, satisfying the requirements in §51.166(q) "public participation".

With respect to Title V procedures for public participation, the above public participation requirement under PSD through noticing in a newspaper of general circulation would suffice. In addition, pursuant to 15A NCAC 02Q .0521, a notice of the DRAFT Title V Permit will be placed on NCDEQ website on xx. The notice will provide for a 30-day comment period with an opportunity for a public hearing. Copies of the public notice will be sent to persons on the Title V mailing list and EPA on xx. Pursuant to 15A NCAC 02Q .0522, a copy of the permit application and the proposed permit (in this case, the draft permit) will be provided to EPA for their 45-day review on xx. Also pursuant to 02Q .0522, a notice of the DRAFT Title V Permit will be provided to each affected State at or before the time notice provided to the public under 02Q .0521 above. A copy of the final permit will also be provided to the EPA upon issuance as per 02Q .0522.

13.0 Stipulation Review

The following changes were made to the CPI USA North Carolina LLC, Roxboro, NC, Air Quality Permit No. 05856T20:

Old Page No. Air Quality Permit No. 05856T20	**New Page No.** Air Quality Permit No. 05856T21	**Condition Number**	**Changes**
3	3	Section 1 Table	Remove applicability / heading of "PSD Avoidance" for boilers (ES-1-1A, 1B, and 1C) as it is erroneous. Remove approval of three SNCR systems (CD-1-7A, 7B, and 7C) and the associated footnote 5 as per the applicant request.
4	4	Section 2.1 Table	Replace "Compliance Assurance Monitoring" with "See Section 2.1A.6." for limits/standards for applicable requirement of 15A NCAC 02D .0614. Remove applicable requirement in 02D .0530(u). Include applicability of 02D .1111 for 5D NESHAP.
6	5	Section 2.1.A.1.c. and d.	Remove coal sulfur content monitoring and revise the reporting to state that compliance with Sections 2.1A.4.dd. and ee. will be sufficient to ensure compliance with 02D .0516.
7	6	Section 2.1.A.2.c. and d.	Consolidate these provisions as both mass-based emission limit and opacity limit are part of standards for particulate matter, the regulated pollutant under NSPS, and renumber them Section 2.1.A.2.b. Include PM standards for "modified" boilers.
6	6	Section 2.1.A.2.b.i.	Include a new PM testing requirement for the modified boilers.
8	8	Section 2.1.A.3.a. through d.	Clarify that the limits for various pollutants in 02D .0501(c) apply during all periods of operation (normal, startup, shutdown, and malfunction). Also clarify the averaging periods as follows: PM_{10}: 3-hour average using stack test SO_2: 24-hour block average using CEMS NO_x: 30-day rolling average using CEMS

Old Page No. Air Quality Permit No. 05856T20	**New Page No.** Air Quality Permit No. 05856T21	**Condition Number**	**Changes**
			CO: 30-day rolling average using CEMS.
8	8	Section 2.1.A.3.e.	Clarify that the averaging period for sulfur content of coal is total shipment average.
9	9	Section 2.1.A.3.j.	Clarify that monitoring and recordkeeping under Section 2.1.A.3.cc. shall apply for SO_2 and no coal sulfur content monitoring shall be required. Include a compliance determination statement that if any 24-hour block average exceeds the SO2 emission limit, the Permittee shall be deemed in non-compliance.
9	-	Section 2.1.A.3.n.	Remove reporting for coal sulfur content.
-	9	Section 2.1.A.3.o.	Include this new provision on reporting of SO_2 emissions per Section 2.1.A.3.dd. and ee.
-	9	Section 2.1.A.3.p.	Include this new provision on reporting of CO emissions per Section 2.1.A.4.o.
10	10	Section 2.1.A.3.aa.	Correct the typo for SO_2 limit of 332.5 lbs/hr (currently written as 322.5 lbs/hr).
10 -	10,11 11	Section 2.1.A.4.a. through e. Section 2.1.A.4.g.	Clarify that the BACT for various pollutants in 02D .0530 apply during all periods of operation (normal, startup, shutdown, and malfunction). Also clarify the averaging periods as follows: PM_{10}: 3-hour average using stack test SO_2: 24-hour block average using CEMS NO_x: 30-day rolling average using CEMS CO: 30-day rolling average using CEMS Sulfuric acid mist: 3-hour average using stack test. Include this new provision for a BACT for the 2009 project for CO as a 30-day rolling average (CEMS) which apply during all periods of operation (normal, startup, shutdown, and malfunction).
11	11	Section 2.1.A.4.h.	Renumber it as Section 2.1A.4.i. Clarify that for complying with BACT for particulate matter (PM_{10}), SO_2, and NOx, the Permittee shall follow the monitoring and recordkeeping requirements in Section 2.1.A.3.g. through i., Section 2.1 A.4.cc., and Section 2.1.A.3.k., respectively.
11	11	Section 2.1.A.4.i.	Replace the CO CEMS requirement per Section 2.1.A.7.k. (non-applicable §112(j) requirement) with Section 2.1.A.8.p.
-	11	Section 2.1.A.4.l.	Include a new provision clarifying that no monitoring for sulfur content of coal and sulfuric acid mist emissions shall be required.
11	-	Section 2.1.A.4.k.	Remove reporting for sulfur content of coal.
11	11	Section 2.1.A.4.l.	Renumber it as Section 2.1.A.4.m. Clarify that reporting requirements in Section 2.1.A.3.m. and n. shall be sufficient to ensure compliance with PM_{10} BACT in Section 2.1.A.4.a.
11	12	Section 2.1.A.4.n. and o.	Remove and consolidate them as Section 2.1.A.4.p., and clarify that the reporting requirements in Section 2.1.A.3.q. and r. shall be sufficient to ensure

Old Page No. Air Quality Permit No. 05856T20	**New Page No.** Air Quality Permit No. 05856T21	**Condition Number**	**Changes**
			compliance with NOx BACT in Section 2.1.A.4.c.
12-14	-	Section 2.1.A.5.	Remove this non-applicable requirement.
14-16	12-15	Section 2.1.A.6.	Renumber it as Section 2.1.A.5. Remove the incorrect applicable requirement of 02Q .0317 with less than 61 tons per consecutive 12-month limit for PM_{10}.
16 through 25	-	Section 2.1.A.7.	Remove this non-applicable requirement.
25 and 26	14-15	Section 2.1.A.8.	Renumber it as Section 2.1.A.6. and change all references accordingly.
26	15	Section 2.1.A.9.	Renumber it as Section 2.1.A.7. and change all references accordingly.
26 through 29	15 through 19	Section 2.1.A.10.	Renumber it as Section 2.1.A.8. and change all references accordingly.
36 through 45	26 through 34	General Conditions	Include the latest set of general conditions (version 5.3, 8/21/18).

14.0 Conclusions, Comments, and Recommendations

- The application discussed in this review do not involve any new control device or any modification to an existing control device. Thus, professional engineer seal requirement in 02Q .0112 does not apply. Although, Wesley Brummer, P.E. (consultant for CPI) has sealed the control device forms for ROFA and FSI, and emissions calculations.

- The application discussed in this review do not involve a new facility or an expansion of an existing facility. Therefore, a consistency determination per 02Q .0507(d)(1) do not apply. However, the applicant did submit a zoning consistency determination request with a copy of the PSD application to Person County Planning and Zoning Department on 9/12/18. The City of Roxboro Planning and Development Director has issued a consistency determination indicating that the "operation is consistent with the applicable zoning ordinance" on 10/2/2018.

- The pre-public notice version of the draft permit was emailed to CPI for review on June 21, 2019. Ginny Grace (on behalf of Terry Nealy, Plant Manager) emailed to DAQ the following comments (copied below within double quotes) on this version of the draft permit on July 2, 2019. The DAQ is including responses below to each of the comments in the same order:

  Company Comment 1:

  "PM Emissions – The multiple requirements for PM included in the permit are somewhat confusing. Please verify that the following information is correct.

  For times when wood is greater than 30% by heat input (during all periods of operation, including shutdown, startup, and malfunction),

  PM is 0.1 lbs/mmBtu (NSPS - 3-hour average)
  PM10 and PM2.5 is 0.027 lbs/mmBtu (BACT and State BACT 3-hr average)
  PM is 5.94 lbs/hr (NAAQS 3-hr average)

  For times when wood is less than 30% by heat input (during all periods of operation, including shutdown, startup, and malfunction),

PM is 0.03 lbs./MMBtu or 0.051 lbs./MMBtu and 0.2 percent of combustion concentration (NSPS 3-hr average)
PM10 and PM2.5 is 0.027 lbs./MMBtu (BACT and State BACT 3-hr average)
PM is 5.94 lbs./hr. (NAAQS 3-hr average)"

DAQ Response:

It is correct that different NSPS standards apply with respect to PM when burning wood.

Specifically, if the modified boiler is burning wood, more than 30 percent annually on a heat input basis, either alone or in combination with other fuel(s), PM standard of 0.10 lb./million Btu would apply. If the modified boiler is burning less than 30 percent wood annually on a heat input basis either alone or in combination with other fuel(s), PM standards of 0.03 lb/million Btu, or 0.051 lb./million Btu heat input and 0.2 percent combustion concentration (99.8 percent reduction) would apply.

No change to the permit language is necessary.

Company Comment 2:

"Air Permit Section 2.1.A.3.e contradicts Section 2.1.A.3.j. Section 2.1.A.3.e should be removed."

DAQ Response:

Section 2.1A.3.e. includes emission limit of coal sulfur content of 1 percent by weight (total shipment average). Section 2.1.A.3.j. states that no monitoring is necessary for coal sulfur content as continuous emission monitoring for SO_2 emissions is required. The DAQ cannot remove coal sulfur limit in the above referred Section, established to comply with the requirement in 02D .0501(c). There is no ambiguity with respect to pollutant limits or monitoring. However, the applicant can comment on the same issue again and DAQ can decide during processing of a renewal application in future. No change to the permit language is necessary.

Company Comment 3:

"Post project performance stack testing has been completed numerous times since the project was completed. CPI would like to get clarification on future PM performance testing requirements, if any, as required under Section 2.1.A.2.d.i. (Note: Facility also required to conduct IB MACT PM testing for filterable particulate only.)"

DAQ Response:

Section 2.1.A.2.d.i. includes a (new) stack testing requirement for PM standards within 180 days of issuance of air permit 05856T21 as the boilers are deemed "modified". The DAQ cannot make any change to this NSPS requirement. The applicant can communicate with DAQ Technical Services Section on whether any prior testing for PM including any NESHAP testing for PM emissions from boiler would satisfy this stack testing requirement of NSPS Subpart Db. No change to the permit language is necessary.

Company Comment 4:

"The permit review states on Page 18 the following:

> "*In addition, as an alternate, the Permittee is allowed to comply with only the emission limit of 1.51 lb/million Btu without the coal fuel sulfur limit of 1.0 percent by weight for SO2 BACT, when using Mobotec's furnace sorbent injection system*".

CPI understands it is the operation of continuous emission monitoring that allows for the removal of the coal fuel sulfur limit. Furnace sorbent injection has not been continuously operated at the Roxboro unit."

DAQ Response:

It is correct that the facility is complying with the SO_2 limit of 1.51 lb/million Btu without using a furnace sorbent injection system in an alternative operating scenario. This alternate scenario was approved several years ago by DAQ for coal burning with higher than 1 percent sulfur when using the sorbent injection system. The DAQ believes that the heading for the operating scenario is confusing as indicates that the Permittee needs to operate the above control system (even if not needed) to comply with the SO_2 limit. Therefore, the DAQ will change the heading of the alternate scenario to state "when burning greater than 1.0 percent by weight sulfur coal (total shipment average)".

Company Comment 5:

"As you requested, comments at this time are focused on modifications included in the draft permit amendment 05856T21. In order to expedite the process, you recommended that any additional permit changes or streamlining suggestions be withheld until permit renewal.

(This would include for example, the addition of language related to the "exclusion of start-up, shutdown, and equipment malfunction periods" when counting the number of opacity incidents that would require a QIP. Such language is included in CPI Southport Title V Permit.)"

DAQ Response:

The DAQ has reviewed the CAM regulation in 40 CFR 64. Per §64.7(c), "data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable".   Accordingly, data recorded during only those events (as described above) can be excluded from complying with the CAM requirements, as included in the permit. Hence, the DAQ will clarify the current CAM plan in Section 2.1.A.5.c. and d. to state accordingly.

- The pre-public notice version of the draft Title V permit was emailed to the Raleigh Regional Office (RRO) for review on June 21, 2019. Dena Pittman (RRO) emailed on July 11, 2019 emailed that she did not have any comments on the draft permit.

- This permit engineer recommends issuing the revised permit after the completion of both public comment and EPA review periods.

Appendix A
RBLC Data

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT AVERAGING PERIOD	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
CA-1225	Sierra Pacific Industries-Anderson Division	4/25/2014	Biomass (clean cellulosic)-fired Stoker Boiler	468 million Btu/hr	Good Combustion Practices	0.23 lb/million Btu	3-Hour Rolling	BACT-PSD	U
VA-0316	Virginia Electric and Power Company Altavista Power Station	5/23/2012	Two Spreader Stoker Boilers (burning woody biomass)	394 million Btu/hr each	Good Combustion Practices	0.3 lb/million Btu	30-Day Rolling	BACT-PSD	U
VA-0317	Virginia Electric and Power Company Hopewell Power Station	5/23/2012	Two Spreader Stoker Boilers (burning woody biomass)	394 million Btu/hr each	Good Combustion Practices	0.3 lb/million Btu	30-Day Rolling	BACT-PSD	U
VA-0318	Virginia Electric and Power Company Southampton Power Station	5/23/2012	Two Spreader Stoker Boilers (burning woody biomass)	394 million Btu/hr each	Good Combustion Practices	0.3 lb/million Btu	30-Day Rolling	BACT-PSD	U
VT-0037	Beaver Wood Energy Fair Haven	2/10/2012	Wood-fired Boiler (type unknown)	482 million Btu/hr each	Good Combustion Practices and Multi-Pollutant Oxidation Catalyst	0.0750 lb/million Btu	24-Hour Rolling	BACT-PSD	U
GA-0140	Georgia Power Co. Mitchell Steam Generating	12/3/2010	Biomass-fired Stoker Boiler	96 MW	Good Combustion Practices	0.45 million Btu/hr	30-Day Rolling	BACT-PSD	U

RBLC ID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT AVERAGING PERIOD	CASE-BY-CASE BASIS	COMPLIANCE VERIFIED
	Plant								
SC-0117	Springs Global US, Inc.	11/6/2010	Wood Biomass Boiler (type unknown)	195 million Btu/hr	Overfire Air and Good Combustion Practices	0.45 million Btu/hr	30-Day Rolling	BACT-PSD	U
CA-1203	Sierra Pacific Industries-Loyalton	8/30/2010	Wood-fired Spreader Stoker Boiler	335.70 million Btu/hr	High Pressure Over-fire Air	1443 ppm @ 12% CO_2, 500 lbs/hr	8-Hour Rolling	BACT-PSD	U
CT-0156	NRG Energy Montvale Power LLC	4/6/2010	Biomass (clean wood)-fired Stoker Boiler	600 million Btu/hr	Oxidation Catalyst	0.10 million Btu/hr	8-Hour Block	BACT-PSD	N
TX-0553	Lindale Renewable Energy LLC	1/8/2010	Biomass-fired Stoker Grate Boiler	73 tons/hr	Good Combustion Practices	0.31 lb/million Btu	30-Day Rolling	BACT-PSD	U
TX-0555	Aspen Power LLC Lufkin Generating Plant	10/26/2009	Wood Waste Derived Stoking Grate Boiler	693 million Btu/hr	Good Combustion Practices	0.075 lb/million Btu	30-Day Rolling	BACT-PSD	U
VA-0309	Georgia Pacific Wood Products-Jarratt	5/15/2008	Coal-fired Keebler Boiler (type unknown)	86.60 million Btu/hr	Good Combustion Practices and CEM System	3.1 lb/hr	-	BACT-PSD	U

Appendix B
Public Notice

Appendix C
Listing of Entities and Documents To be Sent

NEWSPAPER	The Courier-Times P. O. Box 311 Roxboro, NC 27573 (336) 599-0162	Public Notice
OFFICIALS	Ms. Heidi York Manager, Person County 304 S. Morgan Street Roxboro, NC 27573 (336) 597-1720 hyork@personcounty.net	Public Notice
SOURCE	Mr. Terry Nealy Plant Manager CPI USA North Carolina LLC 331 Allie Clay Road Roxboro, NC 27573-1153 (336) 330-4502 tnealy@capitalpower.com	Preliminary Determination, Draft Permit & Public Notice
EPA	Ms. Kelly Fortin Air Permits Section U.S. EPA Region 4 Sam Nunn Atlanta Federal Building 61 Forsyth Street, S.W. Atlanta, Georgia 30303-3104 (404) 562-9185	Preliminary Determination, Draft Permit & Public Notice
	Preliminary Determination, Draft Permit, and Public Notice, via electronic mail to: fortin.kelly@epa.gov with cc to: shepherd.lorinda@epa.gov	
FLM	None	
RALEIGH REGIONAL OFFICE	Mr. Ray Stewart NC DAQ Air Quality Regional Supervisor 3800 Barrett Drive Raleigh, NC 27609 (919) 791-4289 ray.stewart@ncdenr.gov	Preliminary Determination, Draft Permit, & Public Notice